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(54) Abstract Title: **Mono-diameter wellbore casing**

(57) An overlapping joint between a casing 115 and a tubular member 210 is formed by radially expanding the tubular member 210 using an expansion cone. A second expansion cone 805 having a fluid passage 805a is placed proximate the overlapping joint by a support member 815 via a releasable coupling 810 having a fluid passage 810a. A packer 820 is set to isolate a region 830 and the releasable coupling 810 is then released from engagement with the expansion cone 805. The support member 815 moved away from the expansion cone after which a plug 840 is placed in the passage 805a. Injection of fluid 835 pressurises region 830 to cause the cone 805 to be displaced to form a mono-diameter well casing. In another embodiment the releasable coupling is replaced by a slip joint.

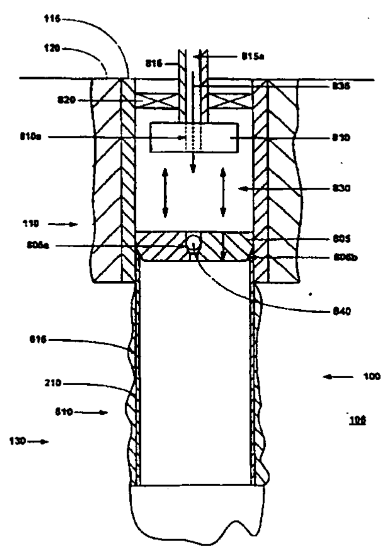

FIGURE 14

GB 2 399 579 A

GB 2399579 A continuation

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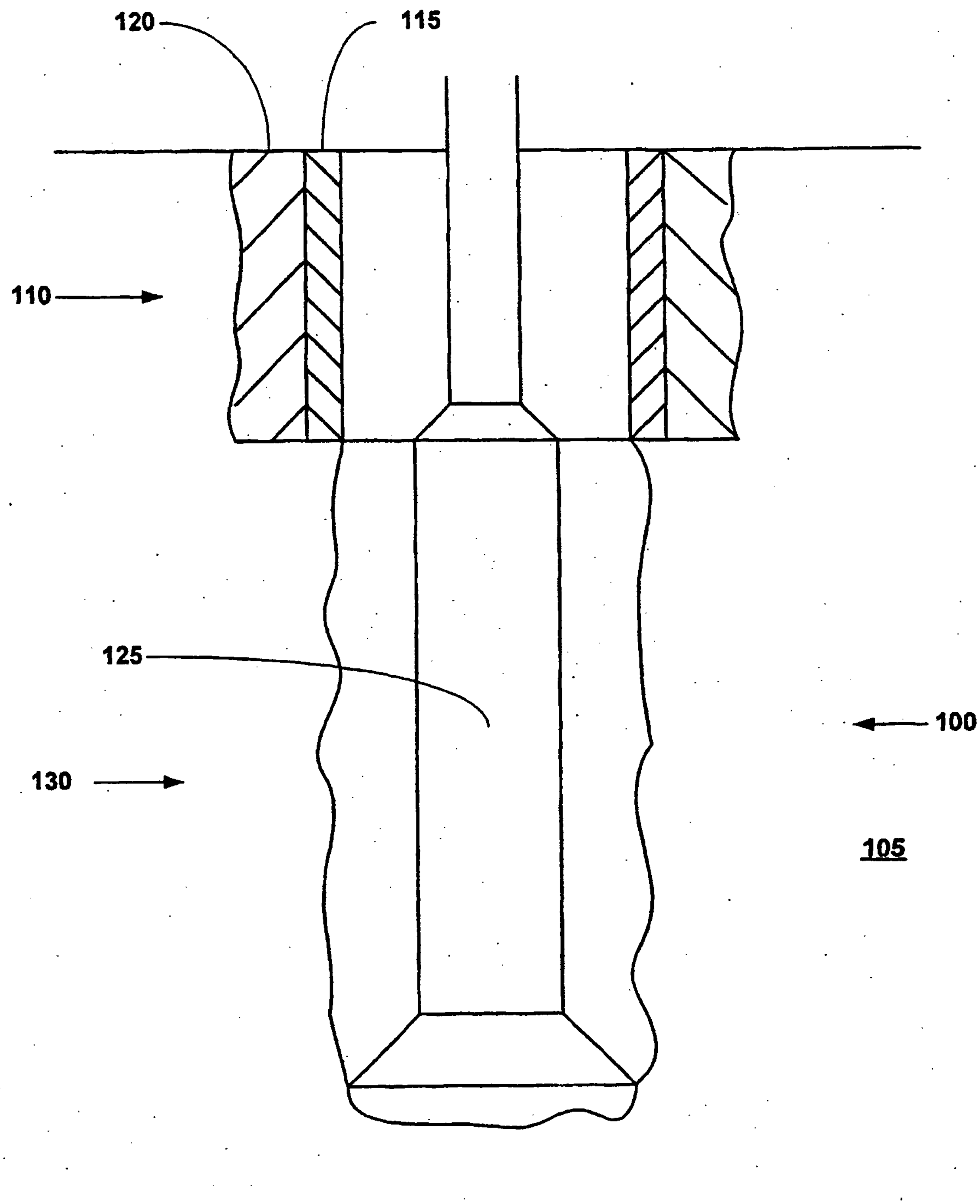
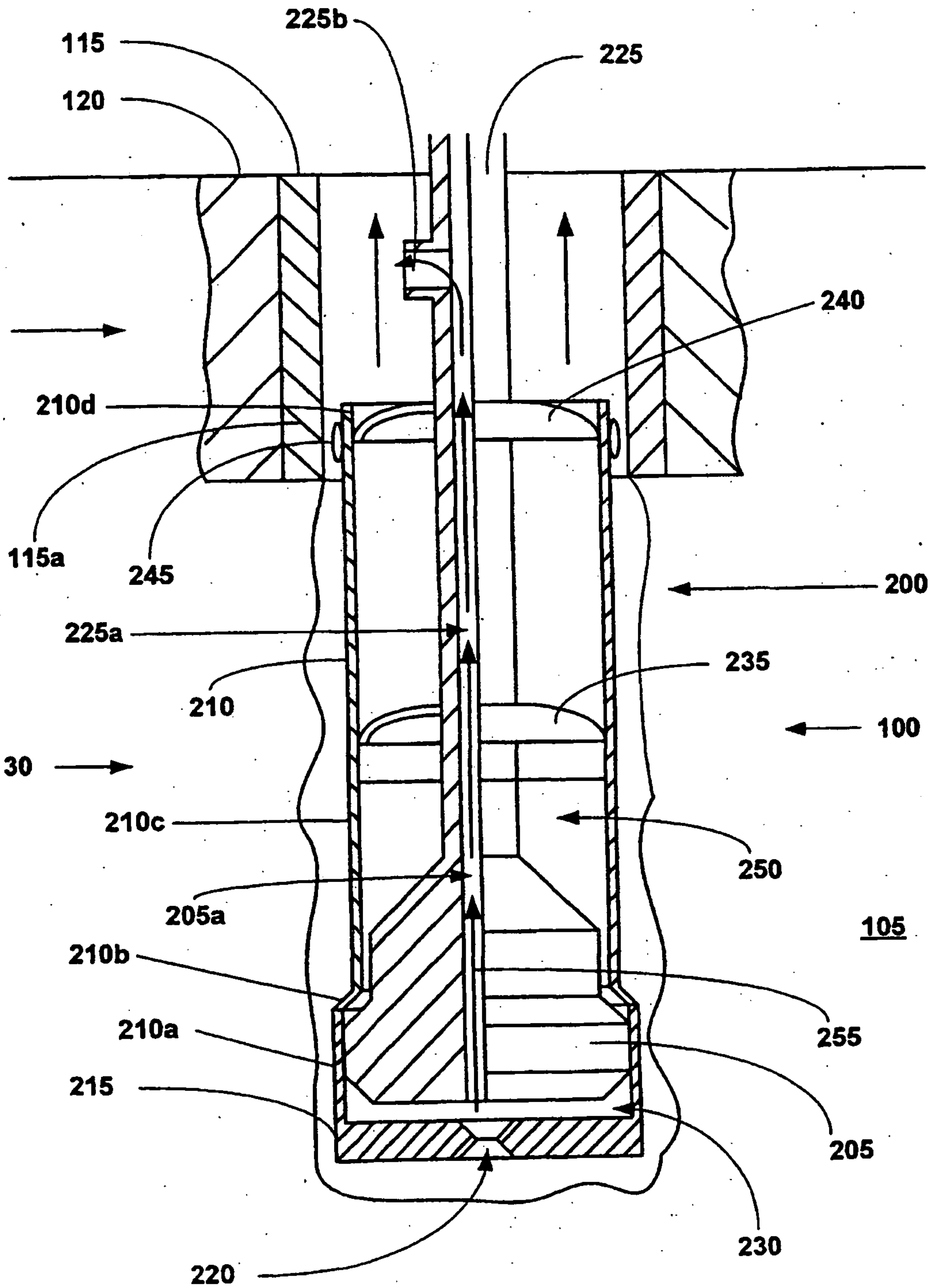


FIGURE 1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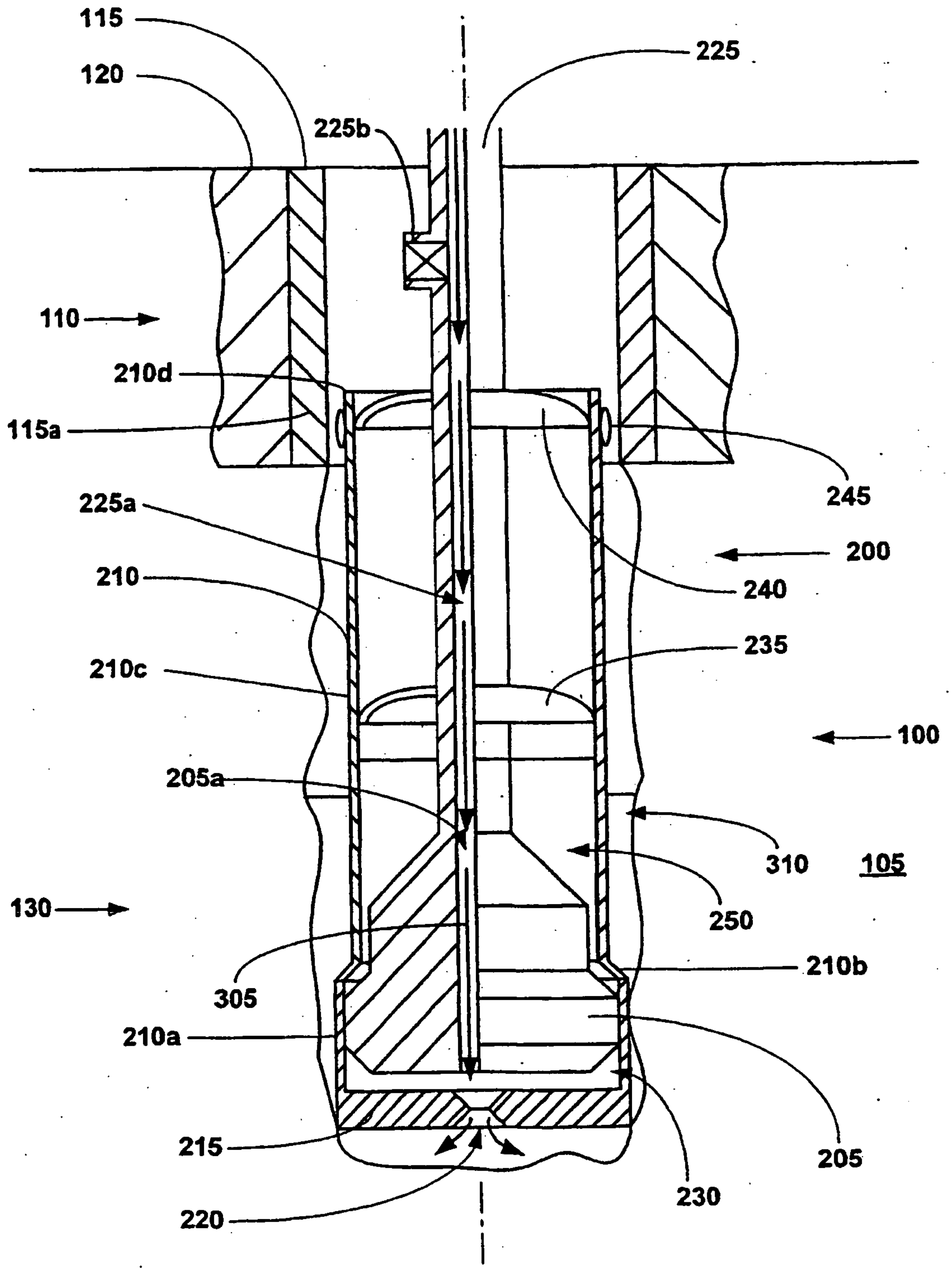
115
225
120
110
240
210d
115a
245
200
225a
235
210
100
130
210c
250
205a
105
210b
255
210a
215
205
230
220

FIGURE 2


115
120
225
225b
110
210d
115a
245
225a
200
240
210
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210c
100
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310
105
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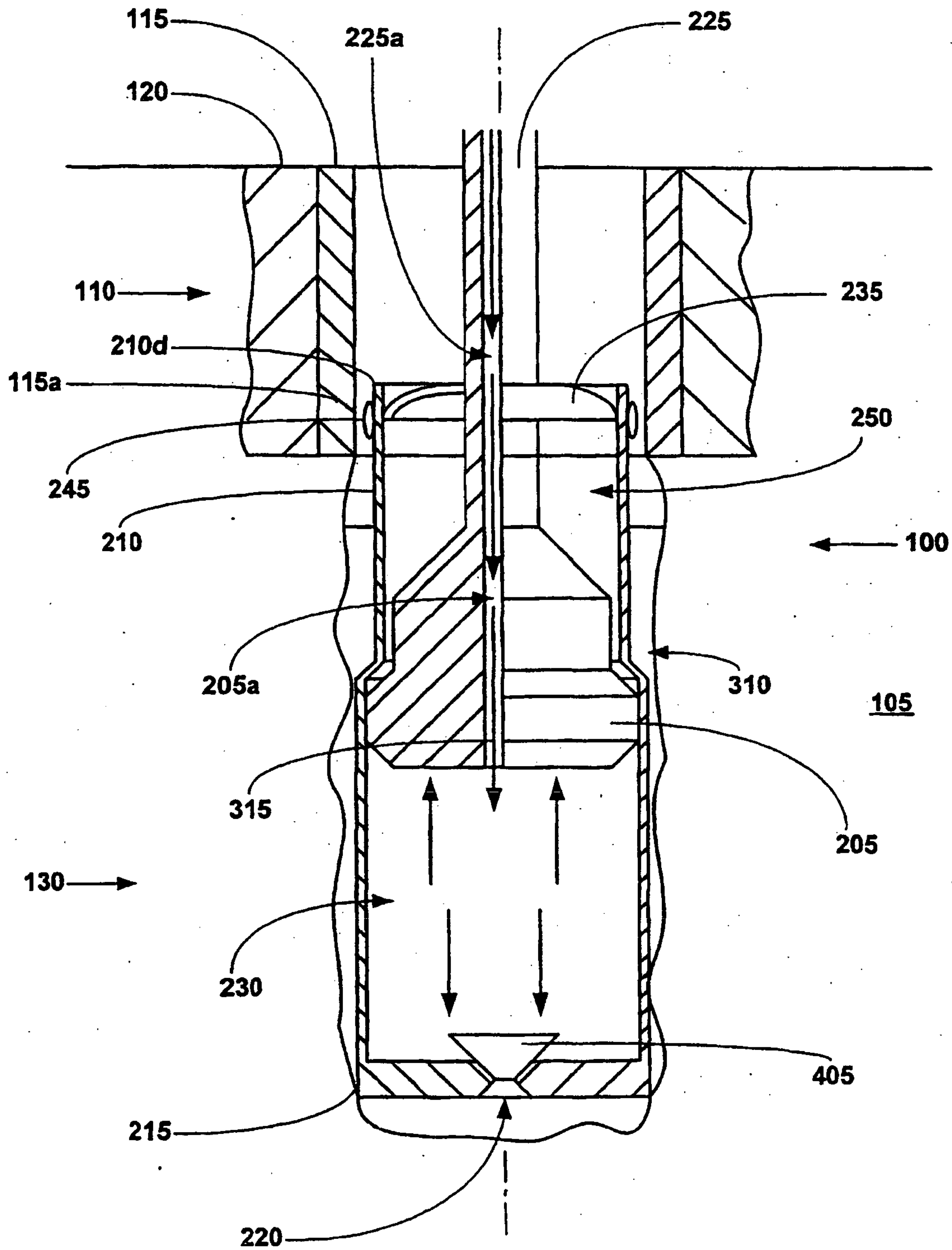
130
210b
305
210a
205
215
230
220

FIGURE 3



115
225a
225
120
110
235
210d
115a
250
245
210
100
205a
310
105
315
205
130
230
405
215
220

FIGURE 4

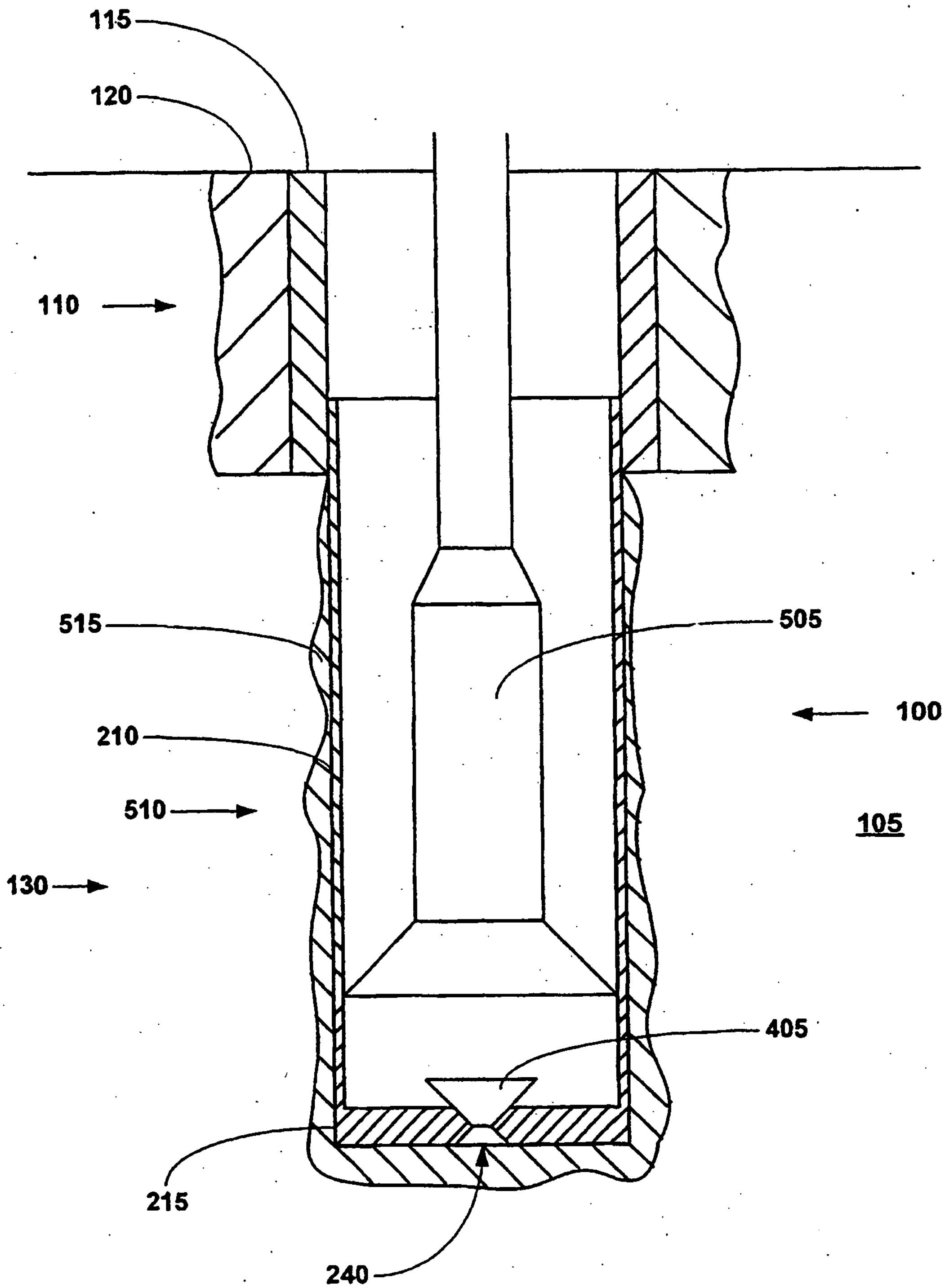


FIGURE 5

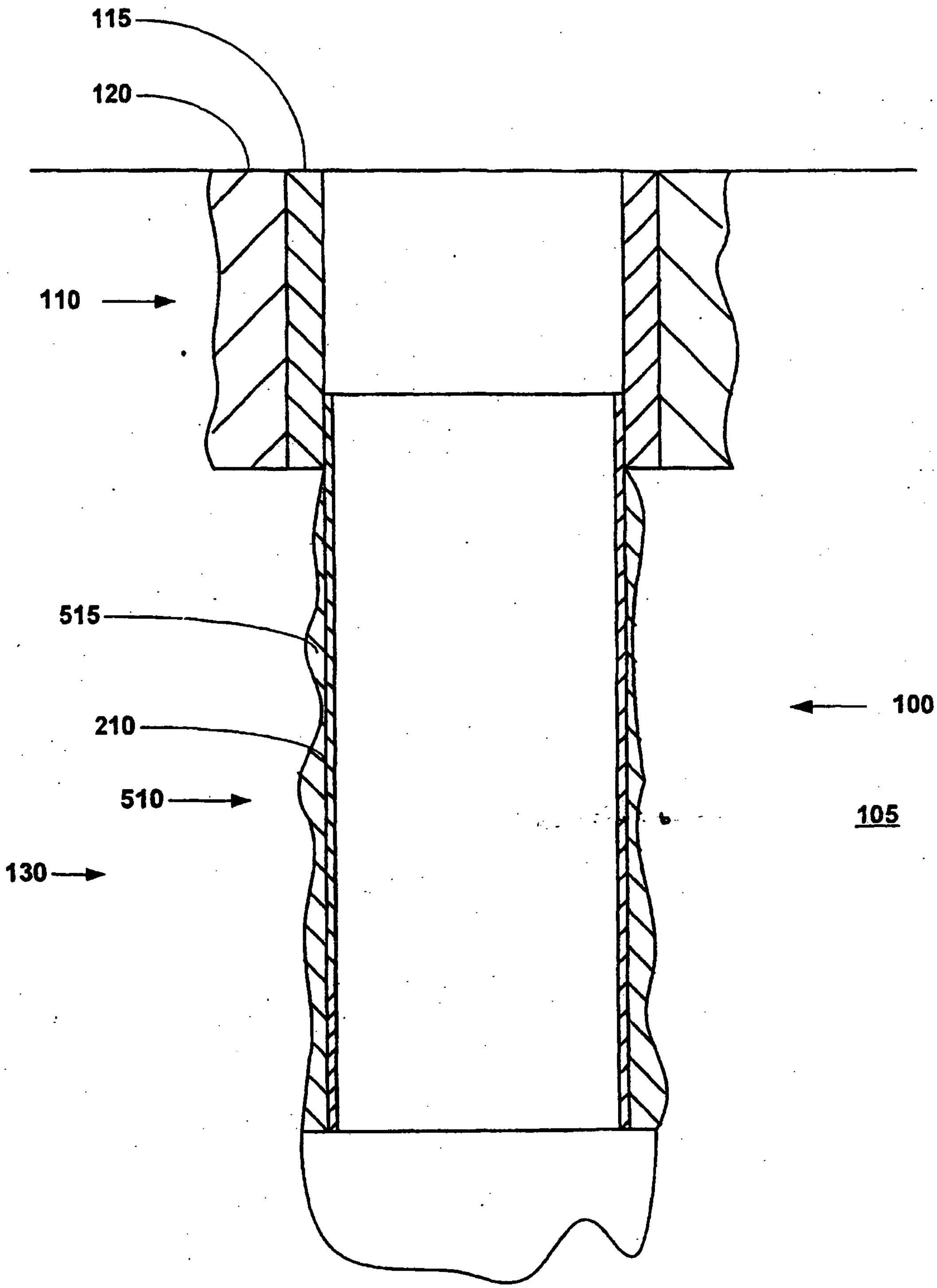


FIGURE 6

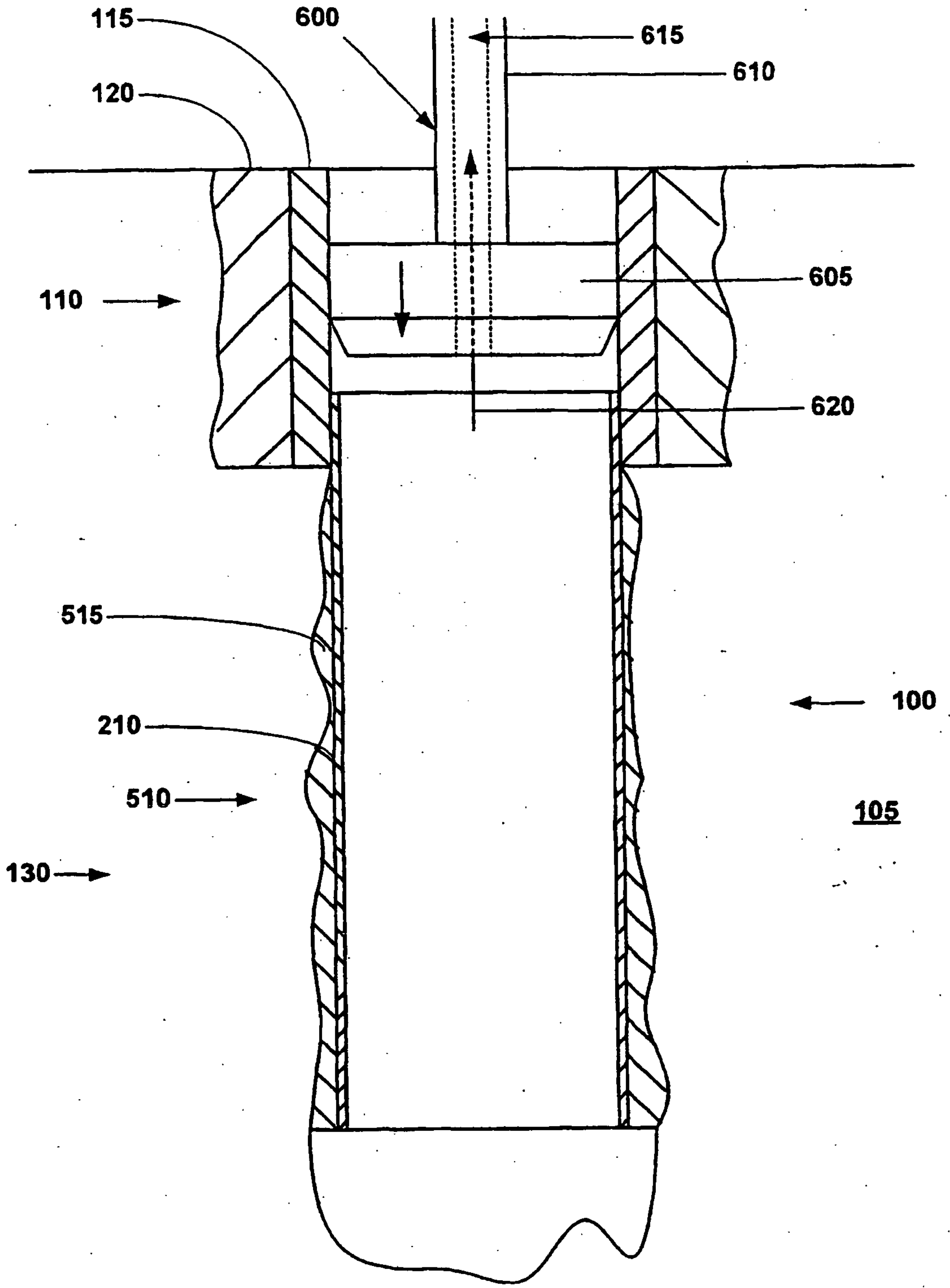


FIGURE 7

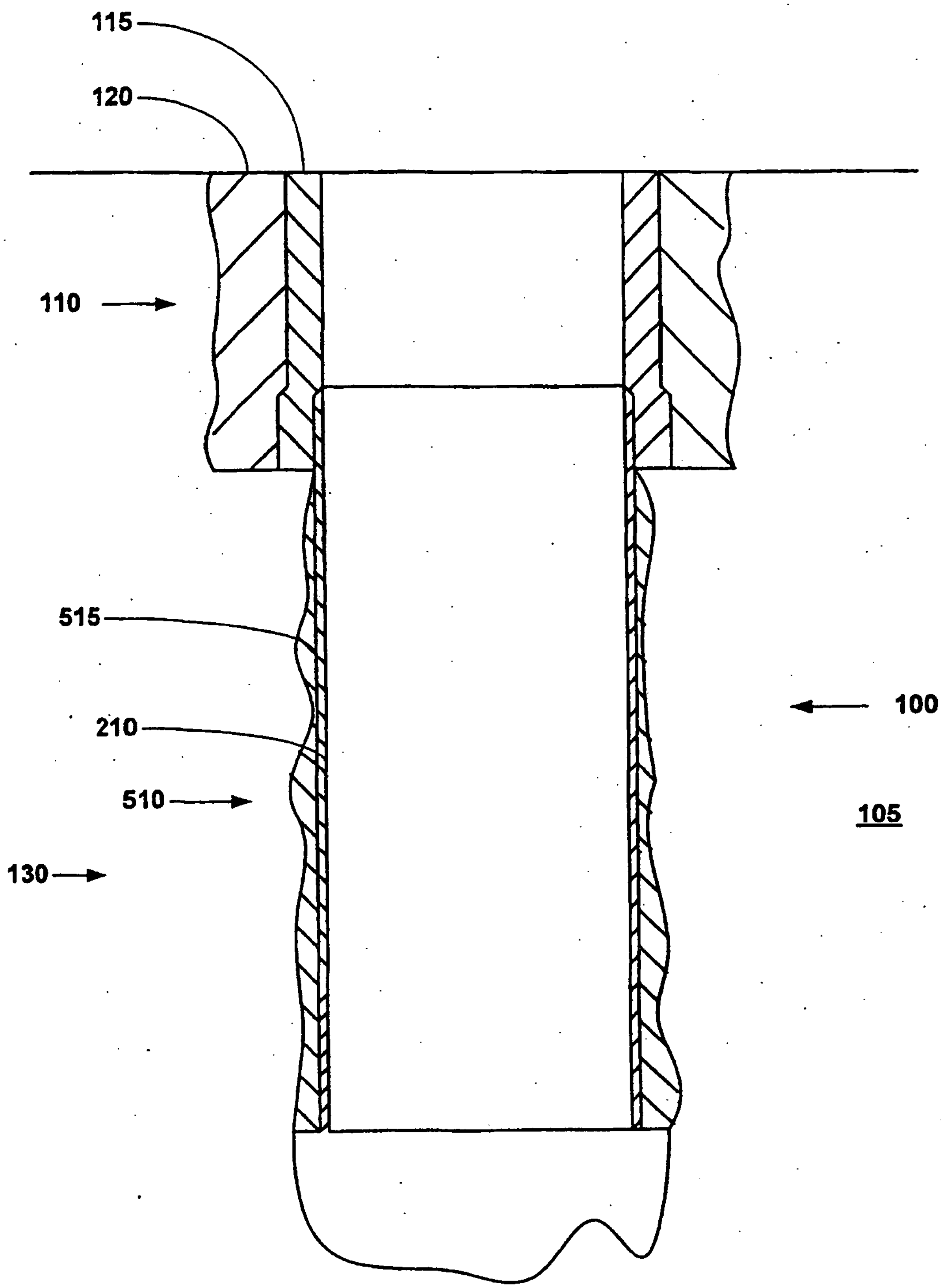


FIGURE 8

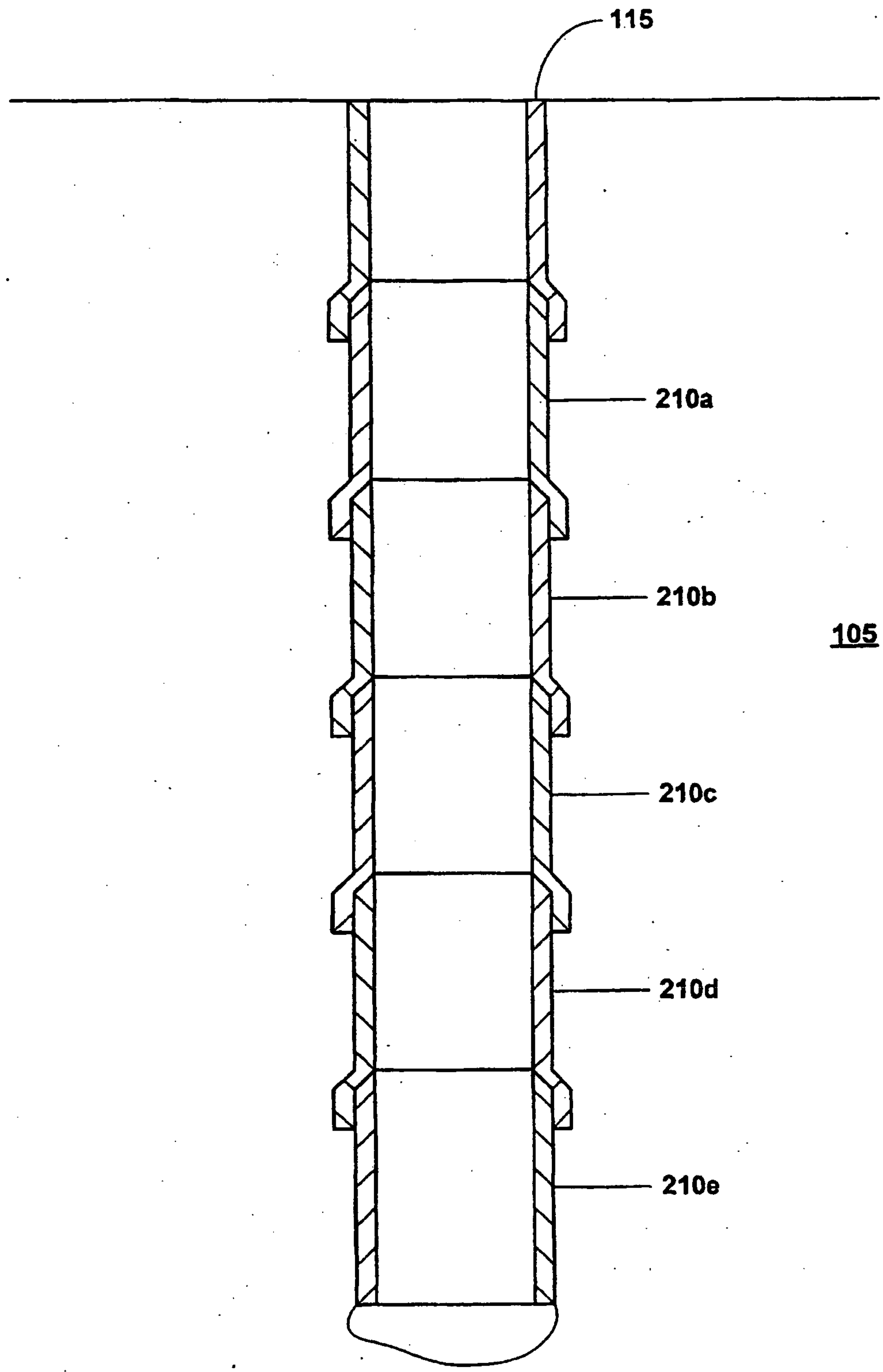


FIGURE 9

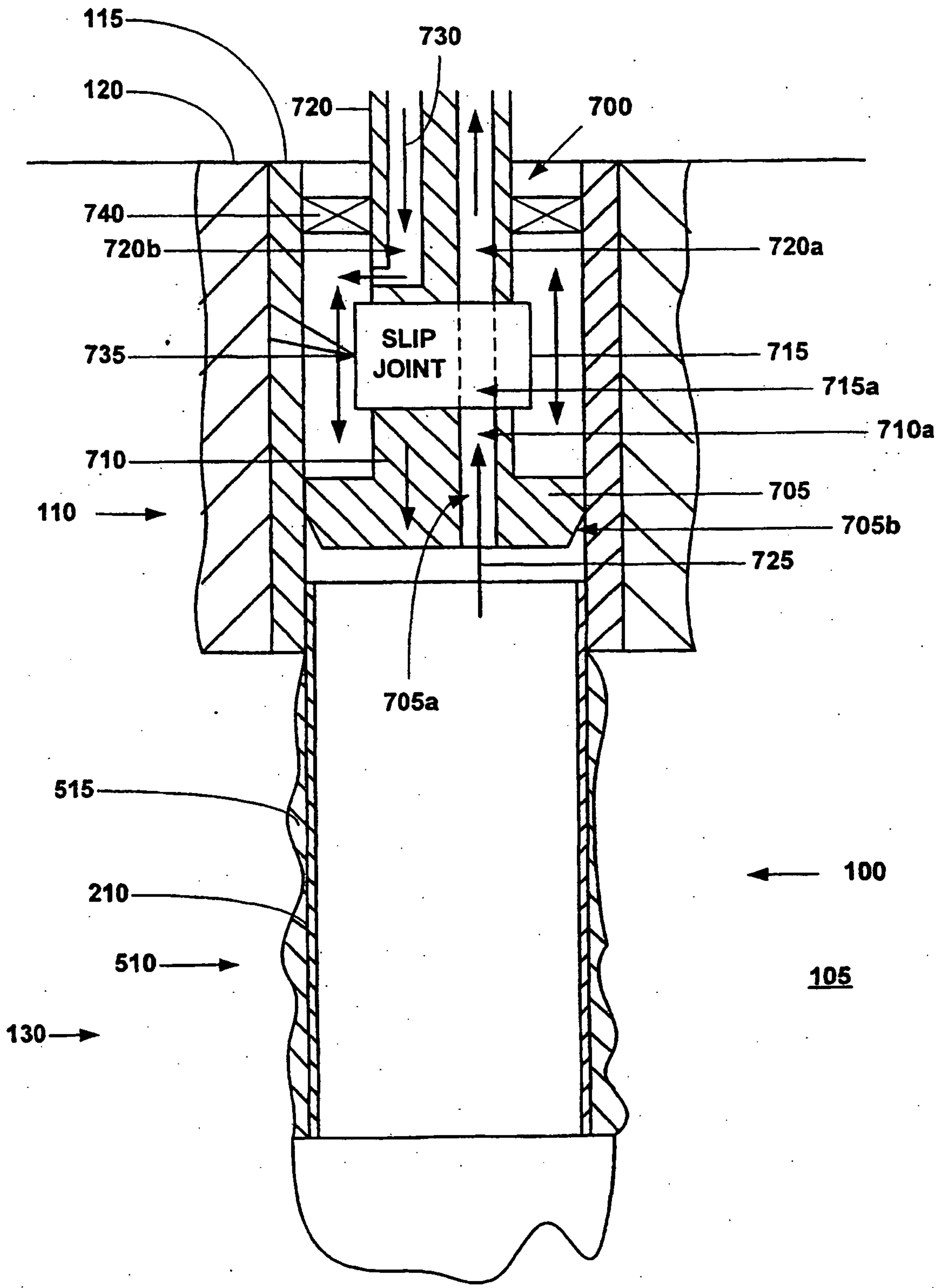

115
730
120
720
700
740
720b
720a
SLIP JOINT
735
715
715a
710a
710
705
110
705b
725
705a
515
100
210
510
105
130

FIGURE 10

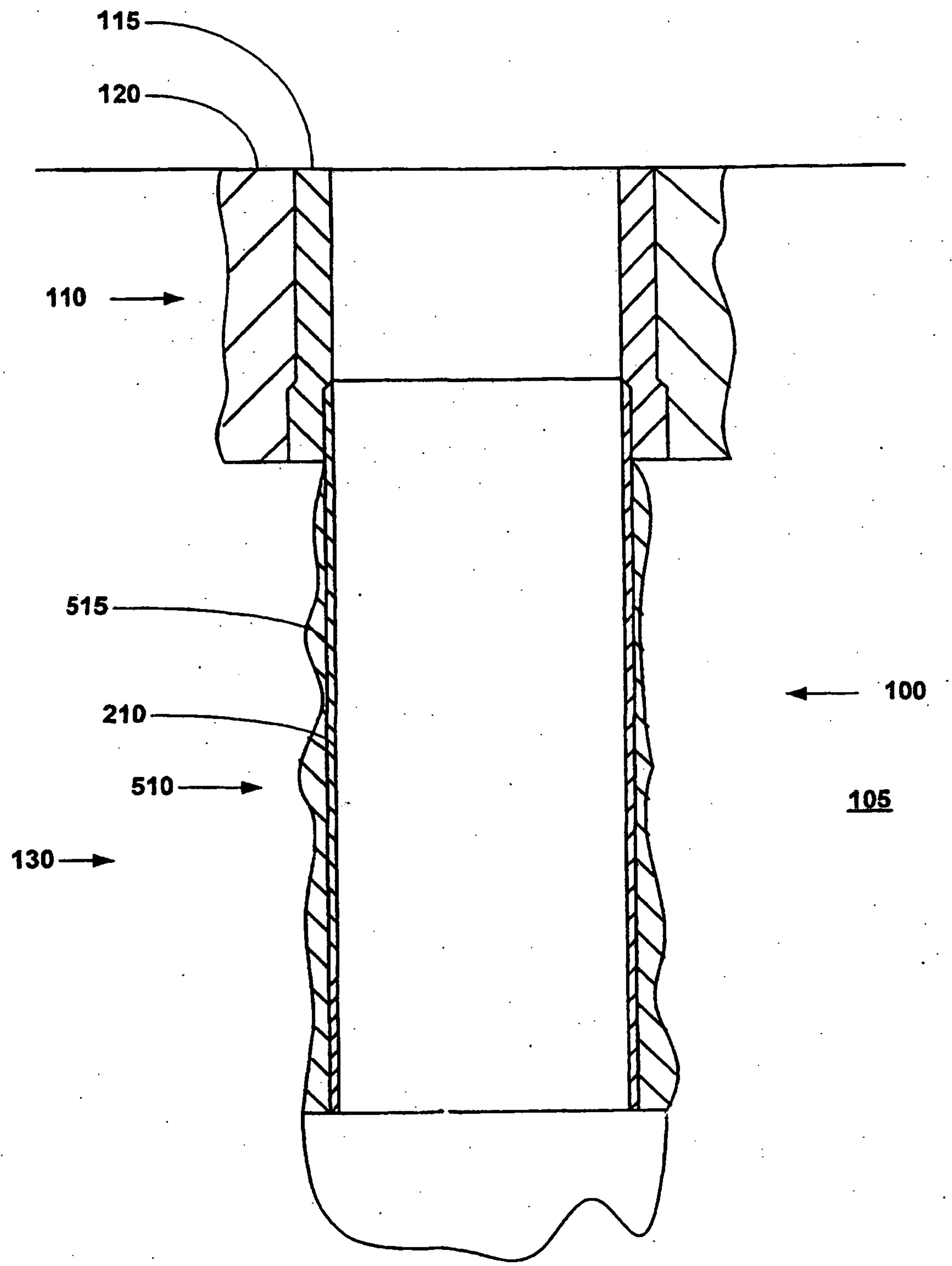


FIGURE 11

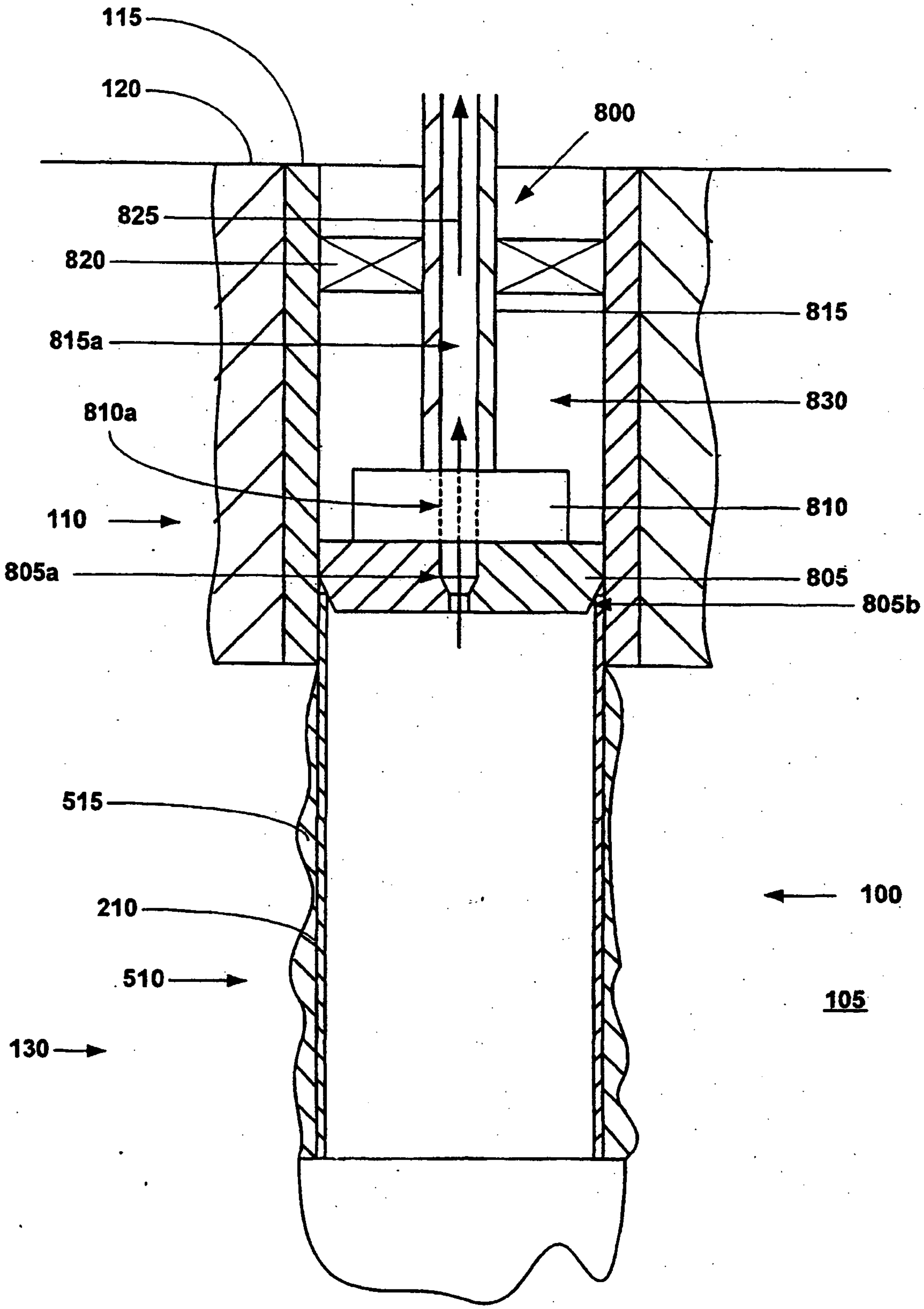

115
120
800
825
820
815
815a
830
810a
810
110
805a
805
805b
515
100
210
510
105
130

FIGURE 12

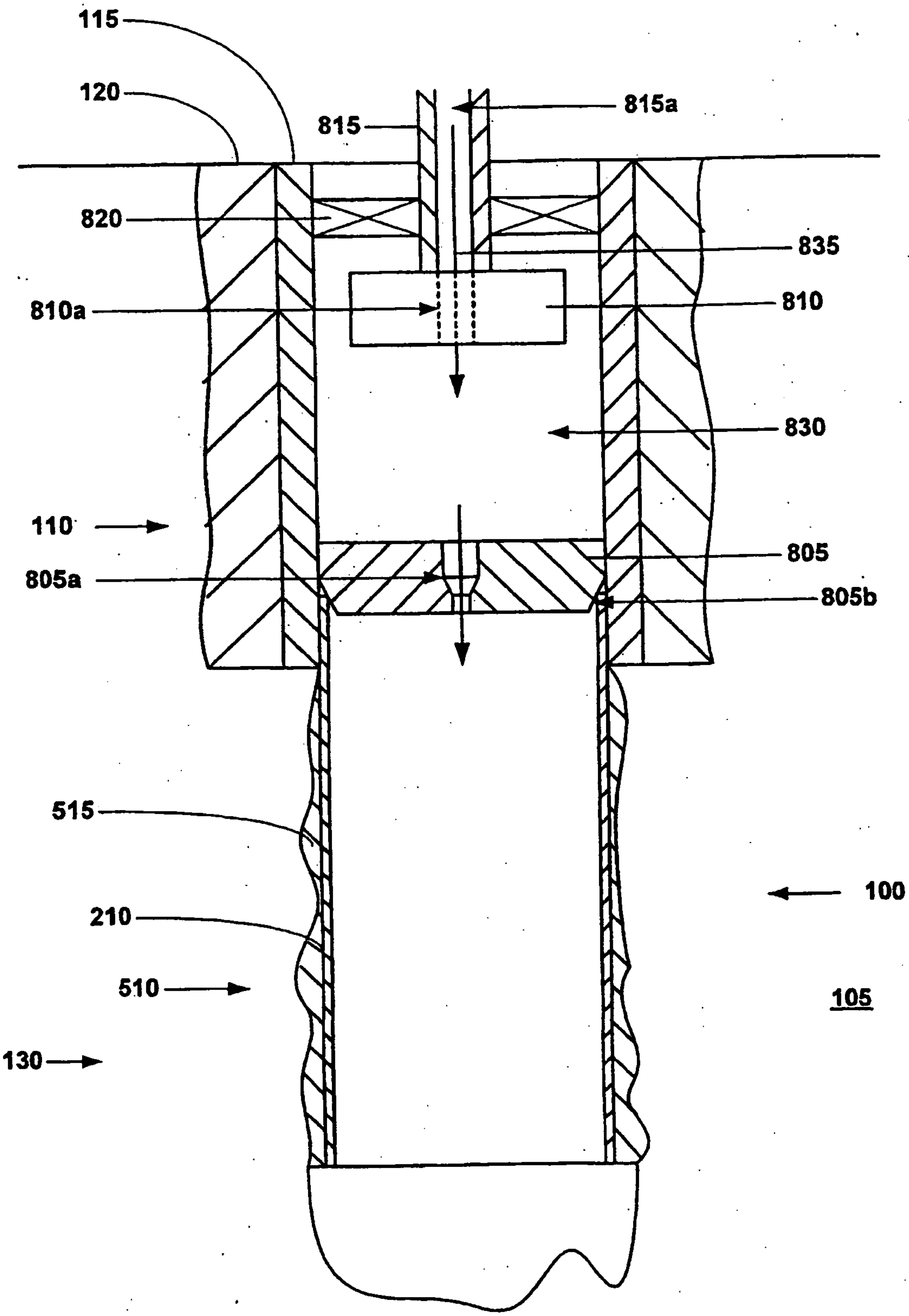
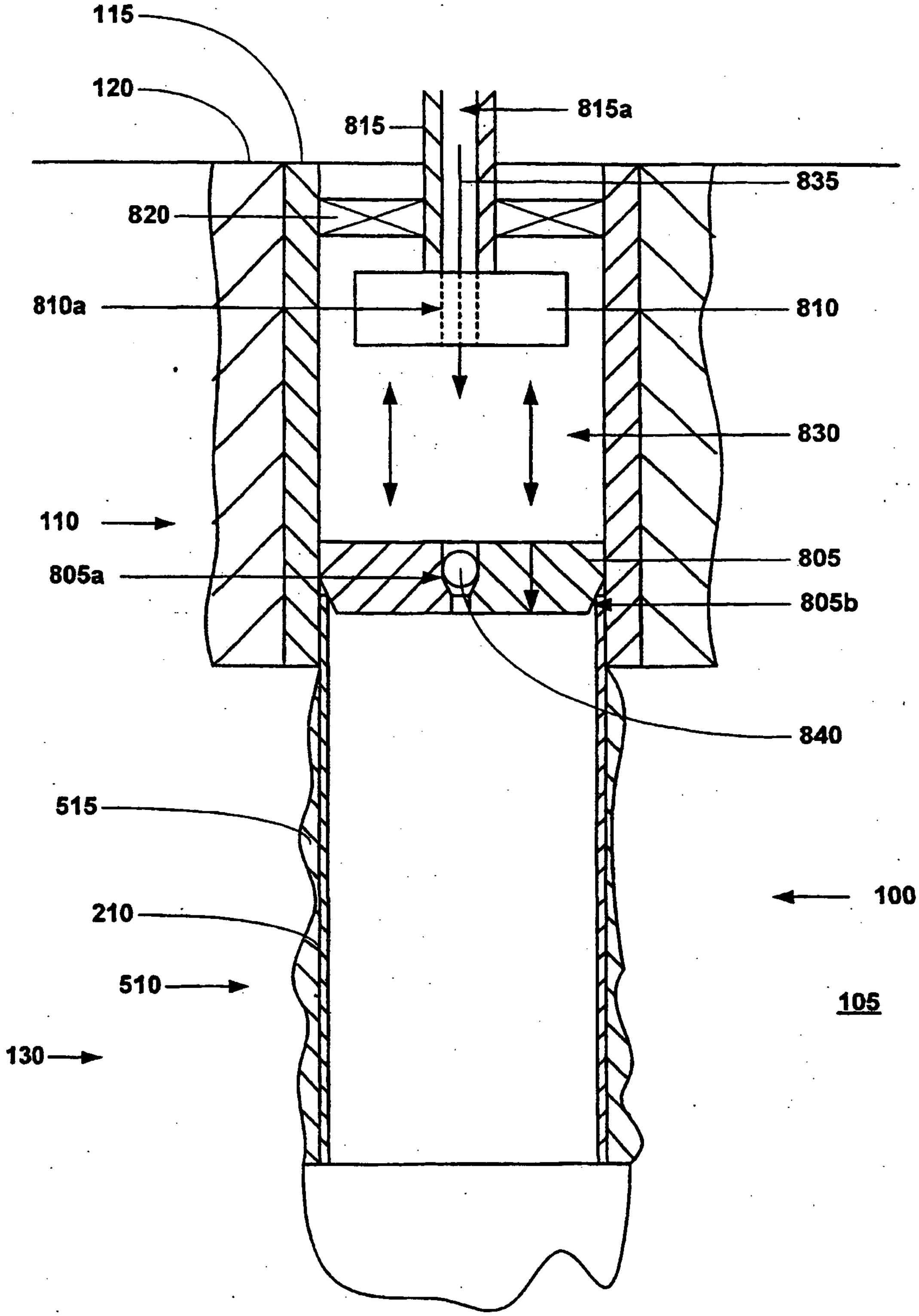

115
120
815
815a
820
835
810a
810
830
110
805
805a
805b
515
100
210
510
105
130

FIGURE 13


115
120
815
815a
835
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810a
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830
110
805
805a
805b
840
515
100
210
510
105
130

FIGURE 14

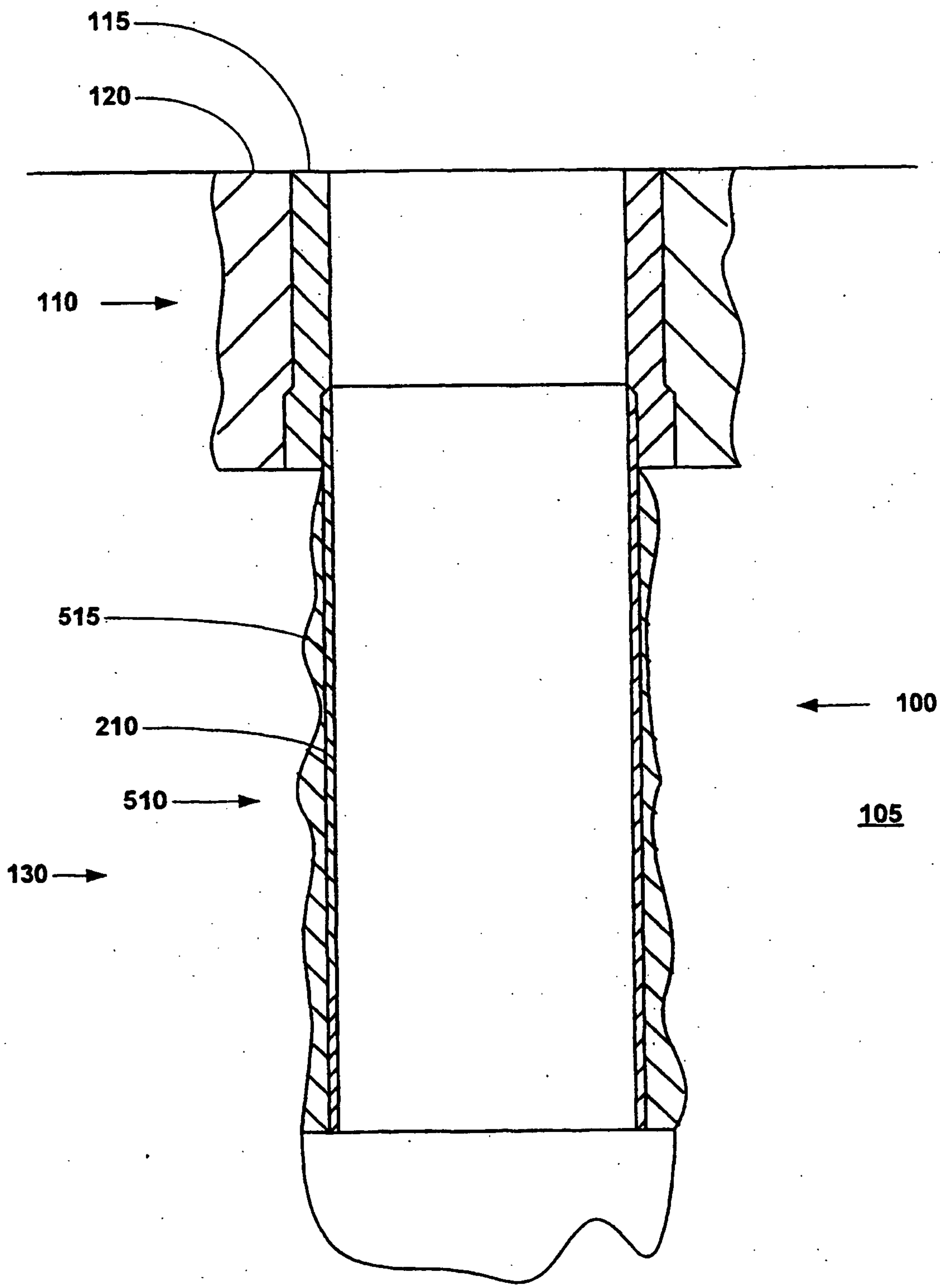

FIGURE 15

2399579

MONO-DIAMETER WELLBORE CASING

Cross Reference To Related Applications

This application is a continuation-in-part of U.S. utility application serial number 09/454,139, attorney docket number 25791.3.02, filed on 12/3/1999, which claimed the benefit of the filing date of U.S. provisional patent application serial number 60/111,293, attorney docket number 25791.3, filed on 12/7/1998, the disclosures of which are incorporated herein by reference.

This application is related to the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on 4/26/2000, (10) PCT patent application serial no. PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no. 25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999,

(18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, and (22) U.S. provisional patent application serial no. ____________, attorney docket no. 25791.52, filed on 1/3/2001, the disclosures of which are incorporated herein by reference.

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming new sections of casing in a

wellbore.

Summary of the Invention

According to one aspect of the present invention, a method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing is provided that includes installing a tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, an apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing is provided that includes means for installing a tubular liner and a first expansion cone in the borehole, means for injecting a fluidic material into the borehole, means for pressurizing a portion of an interior region of the tubular liner below the first expansion cone, means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, a method of joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member is provided that includes positioning a first expansion cone within an interior region of the second tubular member, pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and radially expanding at least a portion of the first tubular member and the second tubular

member using a second expansion cone.

According to another aspect of the present invention, an apparatus for joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is provided that includes means for positioning a first expansion cone within an interior region of the second tubular member, means for pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, means for extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and means for radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

According to another aspect of the present invention, an apparatus is provided that includes a subterranean formation including a borehole, a wellbore casing coupled to the borehole, and a tubular liner coupled to the wellbore casing. The inside diameters of the wellbore casing and the tubular liner are substantially equal, and the tubular liner is coupled to the wellbore casing by a method that includes installing the tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the wellbore casing and the tubular liner using a second expansion cone.

According to another aspect of the present invention, an apparatus is provided that includes a subterranean formation including a borehole, a first tubular member coupled to the borehole, and a second tubular member coupled to the wellbore casing. The inside diameters of the first and second tubular members are substantially equal, and the second tubular member is coupled to the first tubular member by a method that includes installing the second tubular member and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the second tubular member below the

first expansion cone, radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

According to another aspect of the present invention, a method of radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes positioning an expansion cone within the wellbore casing above the overlapping joint, sealing off an annular region within the wellbore casing above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the tubular liner.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off an annular region within the wellbore casing above the expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the tubular liner.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching

member including a second passage fluidicly coupled to the first passage.

According to another aspect of the present invention, a method of radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes positioning an expansion cone within the wellbore casing above the overlapping joint, sealing off a region within the wellbore casing above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner is provided that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off a region within the wellbore casing above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between first and second tubular members is provided that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

According to another aspect of the present invention, a method of radially expanding an overlapping joint between first and second tubular members is provided that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off an annular region within the first tubular member above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the second tubular member.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between first and second tubular members is

provided that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off an annular region within the first tubular member above the expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the second tubular member.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between first and second tubular members is provided that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

According to another aspect of the present invention, a method of radially expanding an overlapping joint between first and second tubular members is provided that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off a region within the first tubular member above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region.

According to another aspect of the present invention, an apparatus for radially expanding an overlapping joint between first and second tubular members is provided that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off a region within the first tubular member above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole of FIG. 1.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a hardenable fluidic sealing material into the new section of the well borehole of FIG. 2.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a fluidic material into the new section of the well borehole of FIG. 3.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of the cured hardenable fluidic sealing material and the shoe from the new section of the well borehole of FIG. 4.

FIG. 6 is a cross-sectional view of the well borehole of FIG. 5 following the drilling out of the shoe.

FIG. 7 is a fragmentary cross-sectional view of the placement and actuation of an expansion cone within the well borehole of FIG. 6 for forming a mono-diameter wellbore casing.

FIG. 8 is a cross-sectional illustration of the well borehole of FIG. 7 following the formation of a mono-diameter wellbore casing.

FIG. 9 is a cross-sectional illustration of the well borehole of FIG. 8 following the repeated operation of the methods of FIGS. 1-8 in order to form a mono-diameter wellbore casing including a plurality of overlapping wellbore casings.

FIG. 10 is a fragmentary cross-sectional illustration of the placement of an alternative embodiment of an apparatus for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 11 is a cross-sectional illustration of the well borehole of FIG. 10 following the formation of a mono-diameter wellbore casing.

FIG. 12 is a fragmentary cross-sectional illustration of the placement of an alternative embodiment of an apparatus for forming a mono-diameter wellbore casing into the well borehole of FIG. 6.

FIG. 13 is a fragmentary cross-sectional illustration of the well borehole of FIG. 12 during the injection of pressurized fluids into the well borehole.

FIG. 14 is a fragmentary cross-sectional illustration of the well borehole of

FIG. 13 during the formation of the mono-diameter wellbore casing.

FIG. 15 is a fragmentary cross-sectional illustration of the well borehole of FIG. 14 following the formation of the mono-diameter wellbore casing.

Detailed Description of the Illustrative Embodiments

Referring initially to FIGS. 1-9, an embodiment of an apparatus and method for forming a mono-diameter wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes a pre-existing cased section 110 having a tubular casing 115 and an annular outer layer 120 of a fluidic sealing material such as, for example, cement. The wellbore 100 may be positioned in any orientation from vertical to horizontal. In several alternative embodiments, the pre-existing cased section 110 does not include the annular outer layer 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new wellbore section 130.

As illustrated in FIG. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expansion cone 205 having a fluid passage 205a that supports a tubular member 210 that includes a lower portion 210a, an intermediate portion 210b, an upper portion 210c, and an upper end portion 210d.

The expansion cone 205 may be any number of conventional commercially available expansion cones. In several alternative embodiments, the expansion cone 205 may be controllably expandable in the radial direction, for example, as disclosed in U.S. patent nos. 5,348,095, and/or 6,012,523, the disclosures of which are incorporated herein by reference.

The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. In several alternative embodiments, the tubular

member 210 may be solid and/or slotted. In a preferred embodiment, the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

The lower portion 210a of the tubular member 210 preferably has a larger inside diameter than the upper portion 210c of the tubular member. In a preferred embodiment, the wall thickness of the intermediate portion 210b of the tubular member 201 is less than the wall thickness of the upper portion 210c of the tubular member in order to faciliate the initiation of the radial expansion process. In a preferred embodiment, the upper end portion 210d of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the expansion cone 205 when it completes the extrusion of tubular member 210.

A shoe 215 is coupled to the lower portion 210a of the tubular member. The shoe 215 includes a valveable fluid passage 220 that is preferably adapted to receive a plug, dart, or other similar element for controllably sealing the fluid passage 220. In this manner, the fluid passage 220 may be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 240.

The shoe 215 may be any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 is an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

In a preferred embodiment, the shoe 215 further includes one or more through and side outlet ports in fluidic communication with the fluid passage 220.

In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210.

A support member 225 having fluid passages 225a and 225b is coupled to the expansion cone 205 for supporting the apparatus 200. The fluid passage 225a is preferably fluidicly coupled to the fluid passage 205a. In this manner, fluidic materials may be conveyed to and from a region 230 below the expansion cone 205 and above the bottom of the shoe 215. The fluid passage 225b is preferably fluidicly coupled to the fluid passage 225a and includes a conventional control valve. In this manner, during placement of the apparatus 200 within the wellbore 100, surge pressures can be relieved by the fluid passage 225b. In a preferred embodiment, the support member 225 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200.

During placement of the apparatus 200 within the wellbore 100, the fluid passage 225a is preferably selected to transport materials such as, for example, drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore 130 which could cause a loss of wellbore fluids and lead to hole collapse. During placement of the apparatus 200 within the wellbore 100, the fluid passage 225b is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

A lower cup seal 235 is coupled to and supported by the support member 225. The lower cup seal 235 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expansion cone 205. The lower cup seal 235 may be any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 235 is a SIP cup seal, available from Halliburton Energy Services

in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

The upper cup seal 240 is coupled to and supported by the support member 225. The upper cup seal 240 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 240 may be any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 240 is a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

One or more sealing members 245 are coupled to and supported by the exterior surface of the upper end portion 210d of the tubular member 210. The seal members 245 preferably provide an overlapping joint between the lower end portion 115a of the casing 115 and the portion 260 of the tubular member 210 to be fluidicly sealed. The sealing members 245 may be any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the sealing members 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the existing casing 115.

In a preferred embodiment, the sealing members 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the sealing members 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

In a preferred embodiment, a quantity of lubricant 250 is provided in the annular region above the expansion cone 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expansion cone 205 is facilitated. The lubricant 250 may be any number of

conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 250 is Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to faciliate the expansion process.

In a preferred embodiment, the support member 225 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

In a preferred embodiment, before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in FIG. 2, in a preferred embodiment, during placement of the apparatus 200 within the wellbore 100, fluidic materials 255 within the wellbore that are displaced by the apparatus are conveyed through the fluid passages 220, 205a, 225a, and 225b. In this manner, surge pressures created by the placement of the apparatus within the wellbore 100 are reduced.

As illustrated in FIG. 3, the fluid passage 225b is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passages 225a and 205a. The material 305 then passes from the fluid passage 205a into the interior region 230 of the tubular member 210 below the expansion cone 205. The material 305 then passes from the interior region 230 into the fluid passage 220. The material 305 then exits the apparatus 200 and fills an annular region 310 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 310.

The material 305 is preferably pumped into the annular region 310 at

pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may be any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 is a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods. In several alternative embodiments, the hardenable fluidic sealing material 305 is compressible before, during, or after curing.

The annular region 310 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 310 of the new section 130 of the wellbore 100 will be filled with the material 305.

In an alternative embodiment, the injection of the material 305 into the annular region 310 is omitted.

As illustrated in FIG. 4, once the annular region 310 has been adequately filled with the material 305, a plug 405, or other similar device, is introduced into the fluid passage 220, thereby fluidicly isolating the interior region 230 from the annular region 310. In a preferred embodiment, a non-hardenable fluidic material 315 is then pumped into the interior region 230 causing the interior region to pressurize. In this manner, the interior region 230 of the expanded tubular member 210 will not contain significant amounts of cured material 305. This also reduces

and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 230 becomes sufficiently pressurized, the tubular member 210 is preferably plastically deformed, radially expanded, and extruded off of the expansion cone 205. During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the expansion cone 205 stationary, and allowing the tubular member 210 to extrude off of the expansion cone 205 and into the new wellbore section 130 under the force of gravity and the operating pressure of the interior region 230.

The plug 405 is preferably placed into the fluid passage 220 by introducing the plug 405 into the fluid passage 225a at a surface location in a conventional manner. The plug 405 preferably acts to fluidicly isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 315.

The plug 405 may be any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the plug 405 is a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 220, the non hardenable fluidic material 315 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 230 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 220, the non

hardenable material 315 is preferably pumped into the interior region 230 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion cone 205, the material composition of the tubular member 210 and expansion cone 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the expansion cone 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expansion cone 205 will begin when the pressure of the interior region 230 reaches, for example, approximately 500 to 9,000 psi.

During the extrusion process, the expansion cone 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expansion cone 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

When thc upper end portion 210d of the tubular member 210 is extruded off of the expansion cone 205, the outer surface of the upper end portion 210d of the tubular member 210 will preferably contact the interior surface of the lower end portion 115a of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

The overlapping joint between the existing casing 115 and the radially expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint. In an alternative embodiment, the sealing members 245 are omitted.

In a preferred embodiment, the operating pressure and flow rate of the non-hardenable fluidic material 315 is controllably ramped down when the expansion cone 205 reaches the upper end portion 210d of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expansion cone 205 can be minimized. In a preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the expansion cone 205 is within about 5 feet from completion of the extrusion process.

Alternatively, or in combination, a shock absorber is provided in the support member 225 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may, for example, be any conventional commercially available shock absorber adapted for use in wellbore operations.

Alternatively, or in combination, an expansion cone catching structure is provided in the upper end portion 210d of the tubular member 210 in order to catch or at least decelerate the expansion cone 205.

Once the extrusion process is completed, the expansion cone 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expansion cone 205, the integrity of the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the preexisting wellbore casing 115 is tested using conventional methods.

In a preferred embodiment, if the fluidic seal of the overlapping joint between the upper end portion 210d of the tubular member 210 and the lower end portion 115a of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 210 is then removed in a

conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The expansion cone 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. In a preferred embodiment, the material 305 within the annular region 310 is then allowed to fully cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 preferably includes the expanded tubular member 210 and an outer annular layer 515 of the cured material 305.

As illustrated in FIG. 6, the bottom portion of the apparatus 200 including the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

As illustrated in FIG. 7, an apparatus 600 for forming a mono-diameter wellbore casing is then positioned within the wellbore casing 115 proximate the tubular member 210 that includes an expansion cone 605 and a support member 610. In a preferred embodiment, the outside diameter of the expansion cone 605 is substantially equal to the inside diameter of the wellbore casing 115. The apparatus 600 preferably further includes a fluid passage 615 for conveying fluidic materials 620 out of the wellbore 100 that are displaced by the placement and operation of the expansion cone 605.

The expansion cone 605 is then driven downward using the support member 610 in order to radially expand and plastically deform the tubular member 210 and the overlapping portion of the tubular member 115. In this manner, as illustrated in FIG. 8, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. In several alternative embodiments, the secondary radial expansion process is performed before, during, or after the material 515 fully cures. In several alternative embodiments, a conventional expansion device including rollers may be substituted for, or used in combination with, the apparatus

600.

More generally, as illustrated in FIG. 9, the method of FIGS. 1-8 is repeatedly performed in order to provide a mono-diameter wellbore casing that includes overlapping wellbore casings 115 and 210a-210e. The wellbore casing 115, and 210a-210e preferably include outer annular layers of fluidic sealing material. In this manner, a mono-diameter wellbore casing may be formed within the subterranean formation that extends for tens of thousands of feet. More generally still, the teachings of FIGS. 1-9 may be used to form a mono-diameter wellbore casing, a pipeline, a structural support, or a tunnel within a subterranean formation at any orientation from the vertical to the horizontal.

In a preferred embodiment, the formation of a mono-diameter wellbore casing, as illustrated in FIGS. 1-9, is further provided as disclosed in one or more of the following: (1) U.S. patent application serial no. 09/454,139, attorney docket no. 25791.03.02, filed on 12/3/1999, (2) U.S. patent application serial no. 09/510,913, attorney docket no. 25791.7.02, filed on 2/23/2000, (3) U.S. patent application serial no. 09/502,350, attorney docket no. 25791.8.02, filed on 2/10/2000, (4) U.S. patent application serial no. 09/440,338, attorney docket no. 25791.9.02, filed on 11/15/1999, (5) U.S. patent application serial no. 09/523,460, attorney docket no. 25791.11.02, filed on 3/10/2000, (6) U.S. patent application serial no. 09/512,895, attorney docket no. 25791.12.02, filed on 2/24/2000, (7) U.S. patent application serial no. 09/511,941, attorney docket no. 25791.16.02, filed on 2/24/2000, (8) U.S. patent application serial no. 09/588,946, attorney docket no. 25791.17.02, filed on 6/7/2000, (9) U.S. patent application serial no. 09/559,122, attorney docket no. 25791.23.02, filed on 4/26/2000, (10) PCT patent application serial no. PCT/US00/18635, attorney docket no. 25791.25.02, filed on 7/9/2000, (11) U.S. provisional patent application serial no. 60/162,671, attorney docket no. 25791.27, filed on 11/1/1999, (12) U.S. provisional patent application serial no. 60/154,047, attorney docket no. 25791.29, filed on 9/16/1999, (13) U.S. provisional patent application serial no. 60/159,082, attorney docket no. 25791.34, filed on 10/12/1999, (14) U.S. provisional patent application serial no. 60/159,039, attorney docket no.

25791.36, filed on 10/12/1999, (15) U.S. provisional patent application serial no. 60/159,033, attorney docket no. 25791.37, filed on 10/12/1999, (16) U.S. provisional patent application serial no. 60/212,359, attorney docket no. 25791.38, filed on 6/19/2000, (17) U.S. provisional patent application serial no. 60/165,228, attorney docket no. 25791.39, filed on 11/12/1999, (18) U.S. provisional patent application serial no. 60/221,443, attorney docket no. 25791.45, filed on 7/28/2000, (19) U.S. provisional patent application serial no. 60/221,645, attorney docket no. 25791.46, filed on 7/28/2000, (20) U.S. provisional patent application serial no. 60/233,638, attorney docket no. 25791.47, filed on 9/18/2000, (21) U.S. provisional patent application serial no. 60/237,334, attorney docket no. 25791.48, filed on 10/2/2000, and (22) U.S. provisional patent application serial no. ____________, attorney docket no. 25791.52, filed on 1/3/2001, the disclosures of which are incorporated herein by reference.

In an alternative embodiment, the fluid passage 220 in the shoe 215 is omitted. In this manner, the pressurization of the region 230 is simplified. In an alternative embodiment, the annular body 515 of the fluidic sealing material is formed using conventional methods of injecting a hardenable fluidic sealing material into the annular region 310.

Referring to FIGS. 10-11, in an alternative embodiment, an apparatus 700 for forming a mono-diameter wellbore casing is positioned within the wellbore casing 115 that includes an expansion cone 705 having a fluid passage 705a that is coupled to a support member 710.

The expansion cone 705 preferably further includes a conical outer surface 705b for radially expanding and plastically deforming the overlapping portion of the tubular member 115 and the tubular member 210. In a preferred embodiment, the outside diameter of the expansion cone 705 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The support member 710 is coupled to a slip joint 715, and the slip joint is coupled to a support member 720. As will be recognized by persons having ordinary skill in the art, a slip joint permits relative movement between objects.

Thus, in this manner, the expansion cone 705 and support member 710 may be displaced in the longitudinal direction relative to the support member 720. In a preferred embodiment, the slip joint 710 permits the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720 for a distance greater than or equal to the axial length of the tubular member 210. In this manner, the expansion cone 705 may be used to plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210 without having to reposition the support member 720.

The slip joint 715 may be any number of conventional commercially available slip joints that include a fluid passage for conveying fluidic materials through the slip joint. In a preferred embodiment, the slip joint 715 is a pumper sub commercially available from Bowen Oil Tools in order to optimally provide elongation of the drill string.

The support member 710, slip joint 715, and support member 720 further include fluid passages 710a, 715a, and 720a, respectively, that are fluidicly coupled to the fluid passage 705a. During operation, the fluid passages 705a, 710a, 715a, and 720a preferably permit fluidic materials 725 displaced by the expansion cone 705 to be conveyed to a location above the apparatus 700. In this manner, operating pressures within the subterranean formation 105 below the expansion cone are minimized.

The support member 720 further preferably includes a fluid passage 720b that permits fluidic materials 730 to be conveyed into an annular region 735 surrounding the support member 710, the slip joint 715, and the support member 720 and bounded by the expansion cone 705 and a conventional packer 740 that is coupled to the support member 720. In this manner, the annular region 735 may be pressurized by the injection of the fluids 730 thereby causing the expansion cone 705 to be displaced in the longitudinal direction relative to the support member 720 to thereby plastically deform and radially expand the overlapping portion of the tubular member 115 and the tubular member 210.

During operation, as illustrated in FIG. 10, in a preferred embodiment, the apparatus 700 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 705 proximate the top of the tubular member 210. During placement of the apparatus 700 within the preexisting casing 115, fluidic materials 725 within the casing are conveyed out of the casing through the fluid passages 705a, 710a, 715a, and 720a. In this manner, surge pressures within the wellbore 100 are minimized.

The packer 740 is then operated in a well-known manner to fluidicly isolate the annular region 735 from the annular region above the packer. The fluidic material 730 is then injected into the annular region 735 using the fluid passage 720b. Continued injection of the fluidic material 730 into the annular region 735 preferably pressurizes the annular region and thereby causes the expansion cone 705 and support member 710 to be displaced in the longitudinal direction relative to the support member 720.

As illustrated in FIG. 11, in a preferred embodiment, the longitudinal displacement of the expansion cone 705 in turn plastically deforms and radially expands the overlapping portion of the tubular member 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the overlapping wellbore casings 115 and 210. The apparatus 700 may then be removed from the wellbore 100 by releasing the packer 740 from engagement with the wellbore casing 115, and lifting the apparatus 700 out of the wellbore 100.

In an alternative embodiment of the apparatus 700, the fluid passage 720b is provided within the packer 740 in order to enhance the operation of the apparatus 700.

In an alternative embodiment of the apparatus 700, the fluid passages 705a, 710a, 715a, and 720a are omitted. In this manner, in a preferred embodiment, the region of the wellbore 100 below the expansion cone 705 is pressurized and one or more regions of the subterranean formation 105 are fractured to enhance the oil and/or gas recovery process.

Referring to FIGS. 12-15, in an alternative embodiment, an apparatus 800 is

positioned within the wellbore casing 115 that includes an expansion cone 805 having a fluid passage 805a that is releasably coupled to a releasable coupling 810 having fluid passage 810a.

The fluid passage 805a is preferably adapted to receive a conventional ball, plug, or other similar device for sealing off the fluid passage. The expansion cone 805 further includes a conical outer surface 805b for radially expanding and plastically deforming the overlapping portion of the tubular member 115 and the tubular member 210. In a preferred embodiment, the outside diameter of the expansion cone 805 is substantially equal to the inside diameter of the pre-existing wellbore casing 115.

The releasable coupling 810 may be any number of conventional commercially available releasable couplings that include a fluid passage for conveying fluidic materials through the releasable coupling. In a preferred embodiment, the releasable coupling 810 is a safety joint commercially available from Halliburton in order to optimally release the expansion cone 805 from the support member 815 at a predetermined location.

A support member 815 is coupled to the releasable coupling 810 that includes a fluid passage 815a. The fluid passages 805a, 810a and 815a are fluidicly coupled. In this manner, fluidic materials may be conveyed into and out of the wellbore 100.

A packer 820 is movably and sealingly coupled to the support member 815. The packer may be any number of conventional packers. In a preferred embodiment, the packer 820 is a commercially available burst preventer (BOP) in order to optimally provide a sealing member.

During operation, as illustrated in FIG. 12, in a preferred embodiment, the apparatus 800 is positioned within the preexisting casing 115 with the bottom surface of the expansion cone 805 proximate the top of the tubular member 210. During placement of the apparatus 800 within the preexisting casing 115, fluidic materials 825 within the casing are conveyed out of the casing through the fluid passages 805a, 810a, and 815a. In this manner, surge pressures within the wellbore

100 are minimized. The packer 820 is then operated in a well-known manner to fluidicly isolate a region 830 within the casing 115 between the expansion cone 805 and the packer 820 from the region above the packer.

In a preferred embodiment, as illustrated in FIG. 13, the releasable coupling 810 is then released from engagement with the expansion cone 805 and the support member 815 is moved away from the expansion cone. A fluidic material 835 may then be injected into the region 830 through the fluid passages 810a and 815a. The fluidic material 835 may then flow into the region of the wellbore 100 below the expansion cone 805 through the valveable passage 805b. Continued injection of the fluidic material 835 may thereby pressurize and fracture regions of the formation 105 below the tubular member 210. In this manner, the recovery of oil and/or gas from the formation 105 may be enhanced.

In a preferred embodiment, as illustrated in FIG. 14, a plug, ball, or other similar valve device 840 may then be positioned in the valveable passage 805a by introducing the valve device into the fluidic material 835. In this manner, the region 830 may be fluidicly isolated from the region below the expansion cone 805. Continued injection of the fluidic material 835 may then pressurize the region 830 thereby causing the expansion cone 805 to be displaced in the longitudinal direction.

In a preferred embodiment, as illustrated in FIG. 15, the longitudinal displacement of the expansion cone 805 plastically deforms and radially expands the overlapping portion of the pre-existing wellbore casing 115 and the tubular member 210. In this manner, a mono-diameter wellbore casing is formed that includes the pre-existing wellbore casing 115 and the tubular member 210. Upon completing the radial expansion process, the support member 815 may be moved toward the expansion cone 805 and the expansion cone may be re-coupled to the releasable coupling device 810. The packer 820 may then be decoupled from the wellbore casing 115, and the expansion cone 805 and the remainder of the apparatus 800 may then be removed from the wellbore 100.

In a preferred embodiment, the displacement of the expansion cone 805 also pressurizes the region within the tubular member 210 below the expansion cone. In

this manner, the subterranean formation surrounding the tubular member 210 may be elastically or plastically compressed thereby enhancing the structural properties of the formation.

A method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing has been described that includes installing a tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

An apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing has also been described that includes means for installing a tubular liner and a first expansion cone in the borehole, means for injecting a fluidic material into the borehole, means for pressurizing a portion of an interior region of the tubular liner below the first

expansion cone, means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the apparatus further includes means for injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

A method of joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member has also been described that includes positioning a first expansion cone within an interior region of the second tubular member, pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of

the first tubular member and the second tubular member using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the method further includes injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

An apparatus for joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, has also been described that includes means for positioning a first expansion cone within an interior region of the second tubular member, means for pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone, means for extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member, and means for radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, the means for radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the means for radially expanding at

least a portion of the first tubular member and the second tubular member using the second expansion cone includes means for displacing the second expansion cone in a longitudinal direction, and means for compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, the means for displacing the second expansion cone in a longitudinal direction includes means for applying fluid pressure to the second expansion cone. In a preferred embodiment, the apparatus further includes means for injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

An apparatus has also been described that includes a subterranean formation including a borehole, a wellbore casing coupled to the borehole, and a tubular liner coupled to the wellbore casing. The inside diameters of the wellbore casing and the tubular liner are substantially equal, and the tubular liner is coupled to the wellbore casing by a method that includes installing the tubular liner and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the tubular liner below the first expansion cone, radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone, and radially expanding at least a portion of the wellbore casing and the tubular liner using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone includes displacing the second expansion cone in a longitudinal direction and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the annular layer

of the fluidic sealing material is formed by a method that includes injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

An apparatus has also been described that includes a subterranean formation including a borehole, a first tubular member coupled to the borehole, and a second tubular member coupled to the wellbore casing. The inside diameters of the first and second tubular members are substantially equal, and the second tubular member is coupled to the first tubular member by a method that includes installing the second tubular member and a first expansion cone in the borehole, injecting a fluidic material into the borehole, pressurizing a portion of an interior region of the second tubular member below the first expansion cone, radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone, and radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and permitting fluidic materials displaced by the second expansion cone to be removed. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, radially expanding at least a portion of the first and second tubular members using the second expansion cone includes displacing the second expansion cone in a longitudinal direction, and compressing at least a portion of the subterranean formation using fluid pressure. In a preferred embodiment, displacing the second expansion cone in a longitudinal direction includes applying fluid pressure to the second expansion cone. In a preferred embodiment, the annular layer of the fluidic sealing material is formed by a method that includes injecting a hardenable fluidic sealing material into an annulus between the first tubular member and the borehole.

An apparatus for radially expanding an overlapping joint between a wellbore

casing and a tubular liner has also been described that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes positioning an expansion cone within the wellbore casing above the overlapping joint, sealing off an annular region within the wellbore casing above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the tubular liner. In a preferred embodiment, the method further includes supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off an annular region within the wellbore casing above the expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the tubular liner. In a preferred embodiment, the apparatus further includes means for supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes positioning an

expansion cone within the wellbore casing above the overlapping joint, sealing off a region within the wellbore casing above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the method further includes pressurizing the interior of the tubular liner.

An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner has also been described that includes means for positioning an expansion cone within the wellbore casing above the overlapping joint, means for sealing off a region within the wellbore casing above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the apparatus further includes means for pressurizing the interior of the tubular liner.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes a tubular support including first and second passages, a sealing member coupled to the tubular support, a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage, and an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

A method of radially expanding an overlapping joint between first and second tubular members has also been described that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off an annular region within the first tubular member above the expansion cone, displacing the expansion cone by pressurizing the annular region, and removing fluidic materials displaced by the expansion cone from the second tubular member. In a preferred embodiment, the method further includes supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off an annular region within the first tubular member above the

expansion cone, means for displacing the expansion cone by pressurizing the annular region, and means for removing fluidic materials displaced by the expansion cone from the second tubular member. In a preferred embodiment, the apparatus further includes means for supporting the expansion cone during the displacement of the expansion cone.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes a tubular support including a first passage, a sealing member coupled to the tubular support, a releasable latching member coupled to the tubular support, and an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

A method of radially expanding an overlapping joint between first and second tubular members has also been described that includes positioning an expansion cone within the first tubular member above the overlapping joint, sealing off a region within the first tubular member above the expansion cone, releasing the expansion cone, and displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the method further includes pressurizing the interior of the second tubular member.

An apparatus for radially expanding an overlapping joint between first and second tubular members has also been described that includes means for positioning an expansion cone within the first tubular member above the overlapping joint, means for sealing off a region within the first tubular member above the expansion cone, means for releasing the expansion cone, and means for displacing the expansion cone by pressurizing the annular region. In a preferred embodiment, the apparatus further includes means for pressurizing the interior of the second tubular member.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it

is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

Claims

1. An apparatus, comprising:

a subterranean formation including a borehole;

a first tubular member coupled to the borehole; and

a second tubular member coupled to the wellbore casing;

wherein the inside diameters of the first and second tubular members are substantially equal; and

wherein the second tubular member is coupled to the first tubular member by a method comprising:

installing the second tubular member and a first expansion cone in the borehole;

injecting a fluidic material into the borehole;

pressurizing a portion of an interior region of the second tubular member below the first expansion cone;

radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone; and

radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

2. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

a tubular support including a first passage;

a sealing member coupled to the tubular support;

a releasable latching member coupled to the tubular support; and

an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

3. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

a tubular support including first and second passages;

a sealing member coupled to the tubular support;

a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage; and

an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

4. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

a tubular support including a first passage;

a sealing member coupled to the tubular support;

a releasable latching member coupled to the tubular support; and

an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

1. A method of creating a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing, comprising:

installing a tubular liner and a first expansion cone in the borehole;

injecting a fluidic material into the borehole;

pressurizing a portion of an interior region of the tubular liner below the first expansion cone;

radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone; and

radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

2. The method of claim 1, wherein radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

permitting fluidic materials displaced by the second expansion cone to be removed.

3. The method of claim 2, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

4. The method of claim 1, wherein radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

compressing at least a portion of the subterranean formation using fluid pressure.

5. The method of claim 4, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

6. The method of claim 1, further comprising:

injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

7. An apparatus for forming a mono-diameter wellbore casing in a borehole located in a subterranean formation including a preexisting wellbore casing, comprising:

means for installing a tubular liner and a first expansion cone in the borehole;

means for injecting a fluidic material into the borehole;

means for pressurizing a portion of an interior region of the tubular liner below the first expansion cone;

means for radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone; and

means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using a second expansion cone.

8. The apparatus of claim 7, wherein the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

means for displacing the second expansion cone in a longitudinal direction; and

means for permitting fluidic materials displaced by the second expansion cone to be removed.

9. The apparatus of claim 8, wherein the means for displacing the second expansion cone in a longitudinal direction comprises:

means for applying fluid pressure to the second expansion cone.

10. The apparatus of claim 7, wherein the means for radially expanding at least a portion of the preexisting wellbore casing and the tubular liner using the second expansion cone comprises:

means for displacing the second expansion cone in a longitudinal direction; and

means for compressing at least a portion of the subterranean formation using fluid pressure.

11. The apparatus of claim 10, wherein the means for displacing the second expansion cone in a longitudinal direction comprises:

means for applying fluid pressure to the second expansion cone.

12. The apparatus of claim 7, further comprising:

means for injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

13. A method of joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, comprising:

positioning a first expansion cone within an interior region of the second tubular member;

pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone;

extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member; and

radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

14. The method of claim 13, wherein radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

permitting fluidic materials displaced by the second expansion cone to be removed.

15. The method of claim 14, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

16. The method of claim 13, wherein radially expanding at least a portion of the first and second tubular members using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

compressing at least a portion of the subterranean formation using fluid pressure.

17. The method of claim 16, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

18. The method of claim 13, further comprising:

injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

19. An apparatus for joining a second tubular member to a first tubular member positioned within a subterranean formation, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, comprising:

means for positioning a first expansion cone within an interior region of the second tubular member;

means for pressurizing a portion of the interior region of the second tubular member adjacent to the first expansion cone;

means for extruding at least a portion of the second tubular member off of the first expansion cone into engagement with the first tubular member; and

means for radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

20. The apparatus of claim 19, wherein the means for radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone comprises:

means for displacing the second expansion cone in a longitudinal direction; and

means for permitting fluidic materials displaced by the second expansion cone to be removed.

21. The apparatus of claim 20, wherein the means for displacing the second expansion cone in a longitudinal direction comprises:

means for applying fluid pressure to the second expansion cone.

22. The apparatus of claim 19, wherein the means for radially expanding at least a portion of the first tubular member and the second tubular member using the second expansion cone comprises:

means for displacing the second expansion cone in a longitudinal direction; and

means for compressing at least a portion of the subterranean formation using fluid pressure.

23. The apparatus of claim 22, wherein the means for displacing the second expansion cone in a longitudinal direction comprises:

means for applying fluid pressure to the second expansion cone.

24. The apparatus of claim 19, further comprising:

means for injecting a hardenable fluidic sealing material into an annulus around the second tubular member.

25. An apparatus, comprising:

a subterranean formation including a borehole;

a wellbore casing coupled to the borehole; and

a tubular liner coupled to the wellbore casing;

wherein the inside diameters of the wellbore casing and the tubular liner are substantially equal; and

wherein the tubular liner is coupled to the wellbore casing by a method comprising:

installing the tubular liner and a first expansion cone in the borehole;

injecting a fluidic material into the borehole;

pressurizing a portion of an interior region of the tubular liner below the first expansion cone;

radially expanding at least a portion of the tubular liner in the borehole by extruding at least a portion of the tubular liner off of the first expansion cone; and

radially expanding at least a portion of the wellbore casing and the tubular liner using a second expansion cone.

26. The apparatus of claim 25, wherein radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

permitting fluidic materials displaced by the second expansion cone to be removed.

27. The apparatus of claim 26, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

28. The apparatus of claim 25, wherein radially expanding at least a portion of the wellbore casing and the tubular liner using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

compressing at least a portion of the subterranean formation using fluid pressure.

29. The apparatus of claim 28, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

30. The apparatus of claim 25, wherein the annular layer of the fluidic sealing material is formed by a method comprising:

injecting a hardenable fluidic sealing material into an annulus between the tubular liner and the borehole.

31. An apparatus, comprising:

a subterranean formation including a borehole;

a first tubular member coupled to the borehole; and

a second tubular member coupled to the wellbore casing;

wherein the inside diameters of the first and second tubular members are substantially equal; and

wherein the second tubular member is coupled to the first tubular member by a method comprising:

installing the second tubular member and a first expansion cone in the borehole;

injecting a fluidic material into the borehole;

pressurizing a portion of an interior region of the second tubular member below the first expansion cone;

radially expanding at least a portion of the second tubular member in the borehole by extruding at least a portion of the second tubular member off of the first expansion cone; and

radially expanding at least a portion of the first tubular member and the second tubular member using a second expansion cone.

26. The apparatus of claim 25, wherein radially expanding at least a portion of the first and second tubular members using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

permitting fluidic materials displaced by the second expansion cone to be removed.

27. The apparatus of claim 26, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

28. The apparatus of claim 25, wherein radially expanding at least a portion of the first and second tubular members using the second expansion cone comprises:

displacing the second expansion cone in a longitudinal direction; and

compressing at least a portion of the subterranean formation using fluid pressure.

29. The apparatus of claim 28, wherein displacing the second expansion cone in a longitudinal direction comprises:

applying fluid pressure to the second expansion cone.

30. The apparatus of claim 25, wherein the annular layer of the fluidic sealing material is formed by a method comprising:

injecting a hardenable fluidic sealing material into an annulus between the first tubular member and the borehole.

31. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

a tubular support including first and second passages;

a sealing member coupled to the tubular support;

a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage; and

an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

32. A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

positioning an expansion cone within the wellbore casing above the overlapping joint;

sealing off an annular region within the wellbore casing above the expansion cone;

displacing the expansion cone by pressurizing the annular region; and

removing fluidic materials displaced by the expansion cone from the tubular liner.

33. The method of claim 32, further comprising:

supporting the expansion cone during the displacement of the expansion cone.

34. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

means for positioning an expansion cone within the wellbore casing above the overlapping joint;

means for sealing off an annular region within the wellbore casing above the expansion cone;

means for displacing the expansion cone by pressurizing the annular region; and

means for removing fluidic materials displaced by the expansion cone from the tubular liner.

35. The apparatus of claim 34, further comprising:

means for supporting the expansion cone during the displacement of the expansion cone.

36. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

a tubular support including a first passage;

a sealing member coupled to the tubular support;

a releasable latching member coupled to the tubular support; and

an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

37. A method of radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

positioning an expansion cone within the wellbore casing above the overlapping joint;

sealing off a region within the wellbore casing above the expansion cone;

releasing the expansion cone; and

displacing the expansion cone by pressurizing the annular region.

38. The method of claim 37, further comprising:

pressurizing the interior of the tubular liner.

39. An apparatus for radially expanding an overlapping joint between a wellbore casing and a tubular liner, comprising:

means for positioning an expansion cone within the wellbore casing above the overlapping joint;

means for sealing off a region within the wellbore casing above the expansion cone;

means for releasing the expansion cone; and

means for displacing the expansion cone by pressurizing the annular region.

40. The apparatus of claim 39, further comprising:

means for pressurizing the interior of the tubular liner.

41. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

a tubular support including first and second passages;

a sealing member coupled to the tubular support;

a slip joint coupled to the tubular support including a third passage fluidicly coupled to the second passage; and

an expansion cone coupled to the slip joint including a fourth passage fluidicly coupled to the third passage.

42. A method of radially expanding an overlapping joint between first and second tubular members, comprising:

positioning an expansion cone within the first tubular member above the overlapping joint;

sealing off an annular region within the first tubular member above the expansion cone;

displacing the expansion cone by pressurizing the annular region; and

removing fluidic materials displaced by the expansion cone from the second tubular member.

43. The method of claim 42, further comprising:

supporting the expansion cone during the displacement of the expansion cone.

44. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

means for positioning an expansion cone within the first tubular member above the overlapping joint;

means for sealing off an annular region within the first tubular member above the expansion cone;

means for displacing the expansion cone by pressurizing the annular region; and

means for removing fluidic materials displaced by the expansion cone from the second tubular member.

45. The apparatus of claim 44, further comprising:

means for supporting the expansion cone during the displacement of the expansion cone.

46. An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

a tubular support including a first passage;

a sealing member coupled to the tubular support;

a releasable latching member coupled to the tubular support; and

an expansion cone releasably coupled to the releasable latching member including a second passage fluidicly coupled to the first passage.

47. A method of radially expanding an overlapping joint between first and second tubular members, comprising:

positioning an expansion cone within the first tubular member above the overlapping joint;

sealing off a region within the first tubular member above the expansion cone;

releasing the expansion cone; and

displacing the expansion cone by pressurizing the annular region.

48. The method of claim 47, further comprising:

pressurizing the interior of the second tubular member.

49. .An apparatus for radially expanding an overlapping joint between first and second tubular members, comprising:

means for positioning an expansion cone within the first tubular member above the overlapping joint;

means for sealing off a region within the first tubular member above the expansion cone;

means for releasing the expansion cone; and

means for displacing the expansion cone by pressurizing the annular region.

50. The apparatus of claim 49, further comprising:

means for pressurizing the interior of the second tubular member.

51. The method of claim 1, wherein the inside diameter of the portion of the tubular liner radially expanded by the first expansion cone is equal to the inside

diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

52. The apparatus of claim 7, wherein the inside diameter of the portion of the tubular liner radially expanded by the first expansion cone is equal to the inside diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

53. The method of claim 13, wherein the inside diameter of the portion of the tubular liner extruded off of the first expansion cone is equal to the inside diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

54. The apparatus of claim 19, wherein the inside diameter of the portion of the tubular liner extruded off of the first expansion cone is equal to the inside diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

55. The apparatus of claim 25, wherein the inside diameter of the portion of the tubular liner radially expanded by the first expansion cone is equal to the inside diameter of the portion of the preexisting wellbore casing that was not radially expanded by the second expansion cone.

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Application No:	GB0411892.3	50	**Examiner:**	David Pepper
Claims searched:	1		**Date of search:**	14 July 2004

Patents Act 1977: Search Report under Section 17

Documents considered to be relevant:

Category	Relevant to claims	Identity of document and passage or figure of particular reference
X,E	1	GB 2392686 A (Enventure Global Tech) - see figs 11a-c and page 42, line 25 to page 43, line 16
X,P	1	GB 2368865 A (Enventure Global Tech) - see figs 53a-c and page 273, line 17 to page 277, line 13

Categories:

X	Document indicating lack of novelty or inventive step	A	Document indicating technological background and/or state of the art.
Y	Document indicating lack of inventive step if combined with one or more other documents of same category.	P	Document published on or after the declared priority date but before the filing date of this invention.
&	Member of the same patent family	E	Patent document published on or after, but with priority date earlier than, the filing date of this application.

Field of Search:

Search of GB, EP, WO & US patent documents classified in the following areas of the UKC^{W} :

E1F

Worldwide search of patent documents classified in the following areas of the IPC^{07}

E21B

The following online and other databases have been used in the preparation of this search report

Online: WPI, EPODOC, JAPIO

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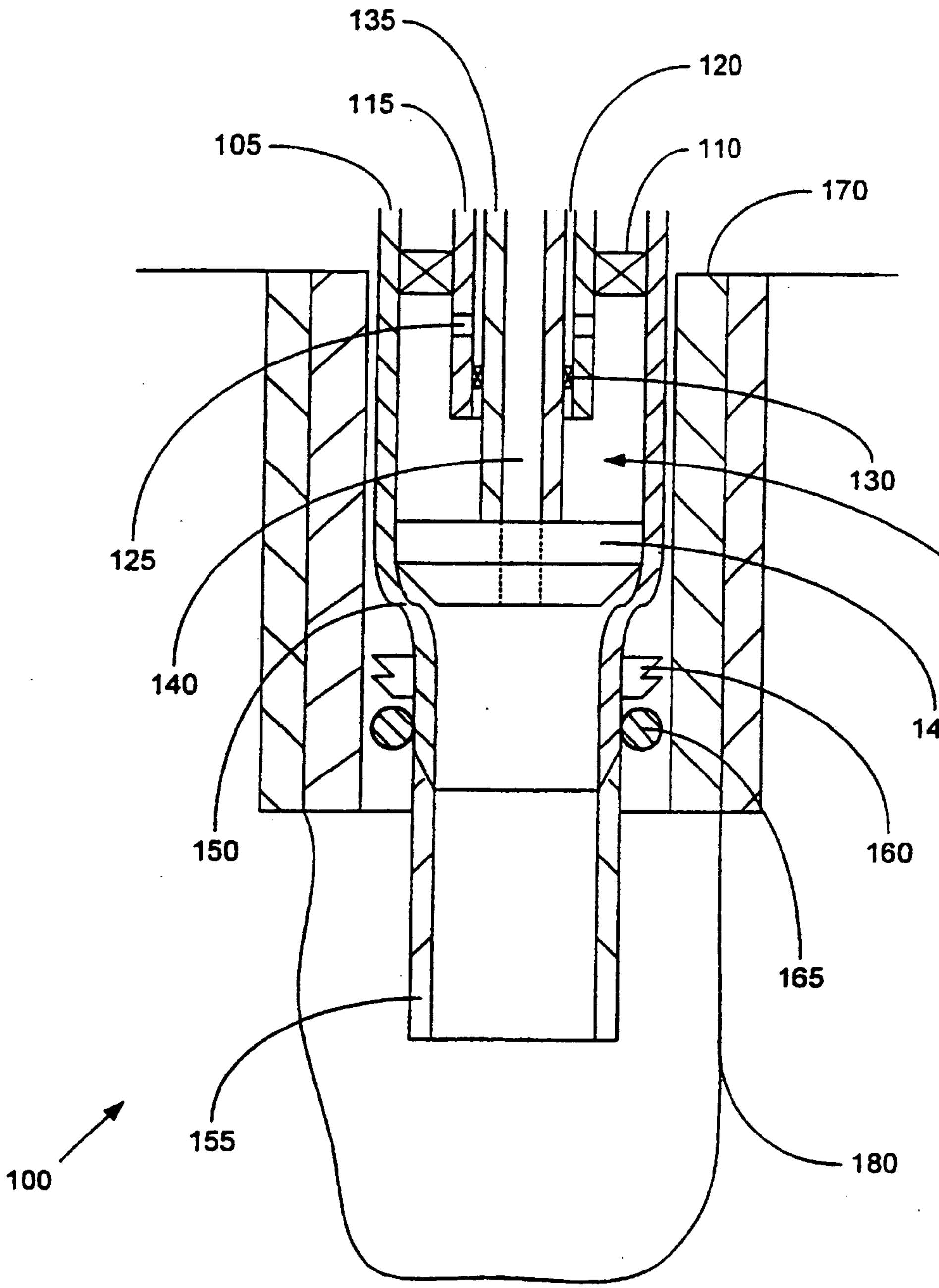

FIG. 1a

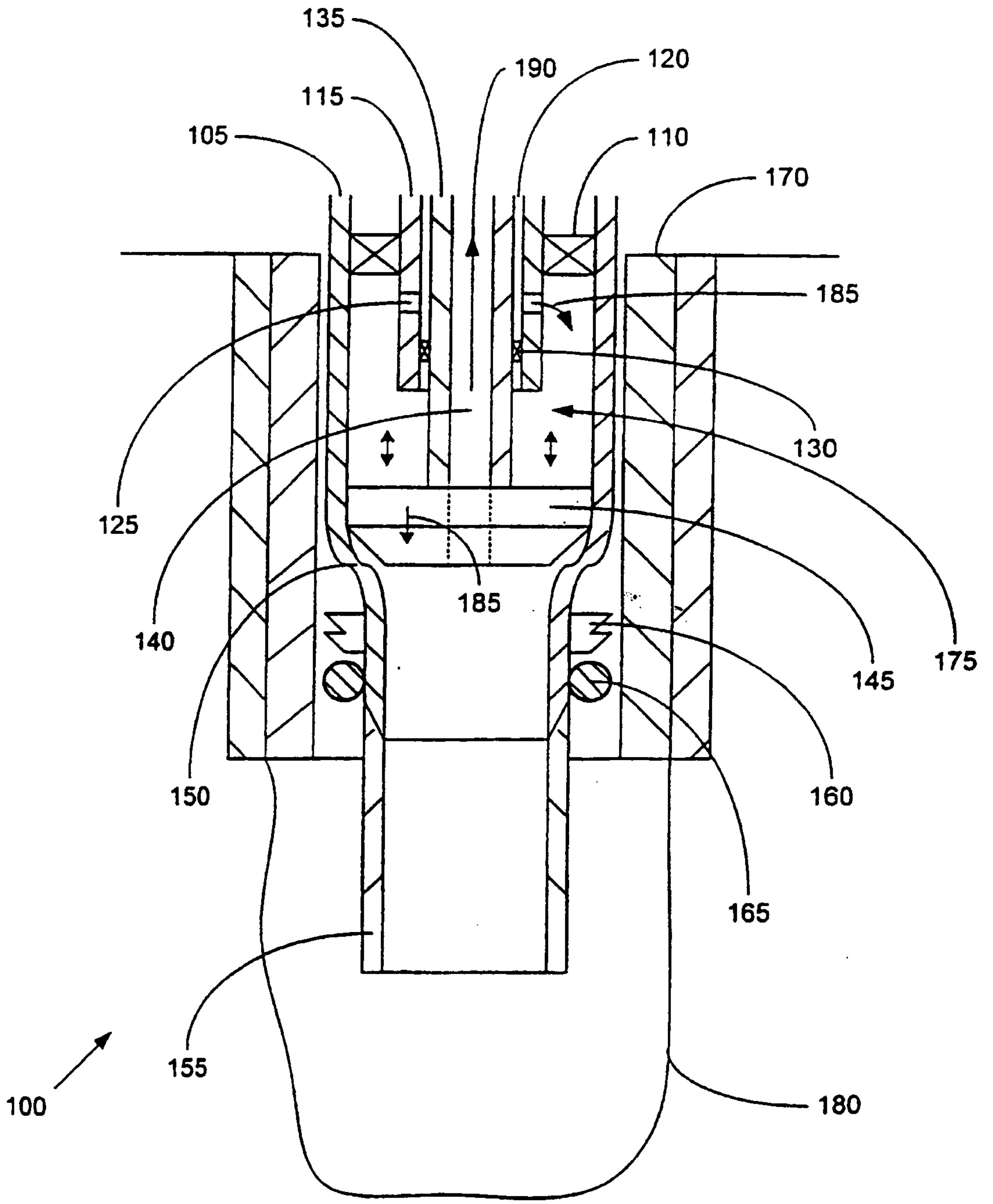
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FIG. 1b

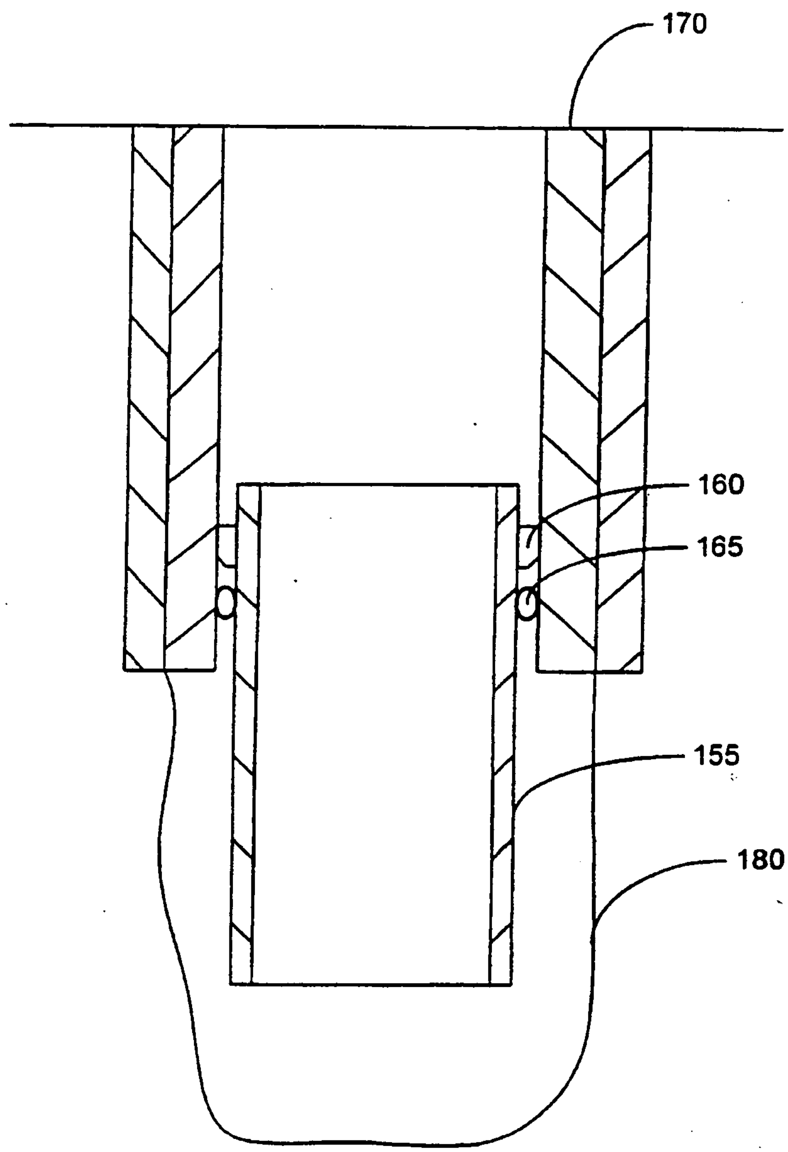

FIG. 1c

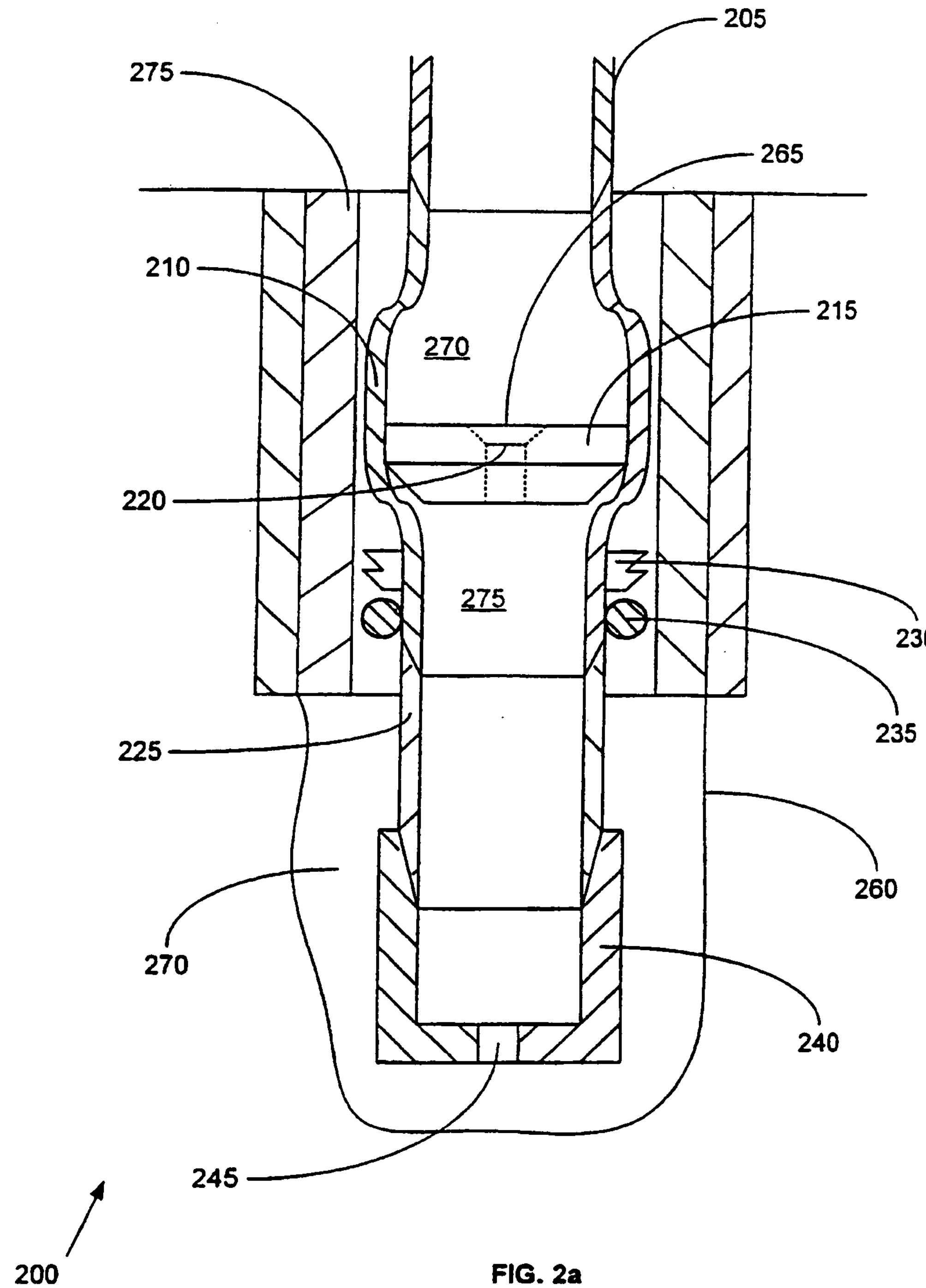

FIG. 2a

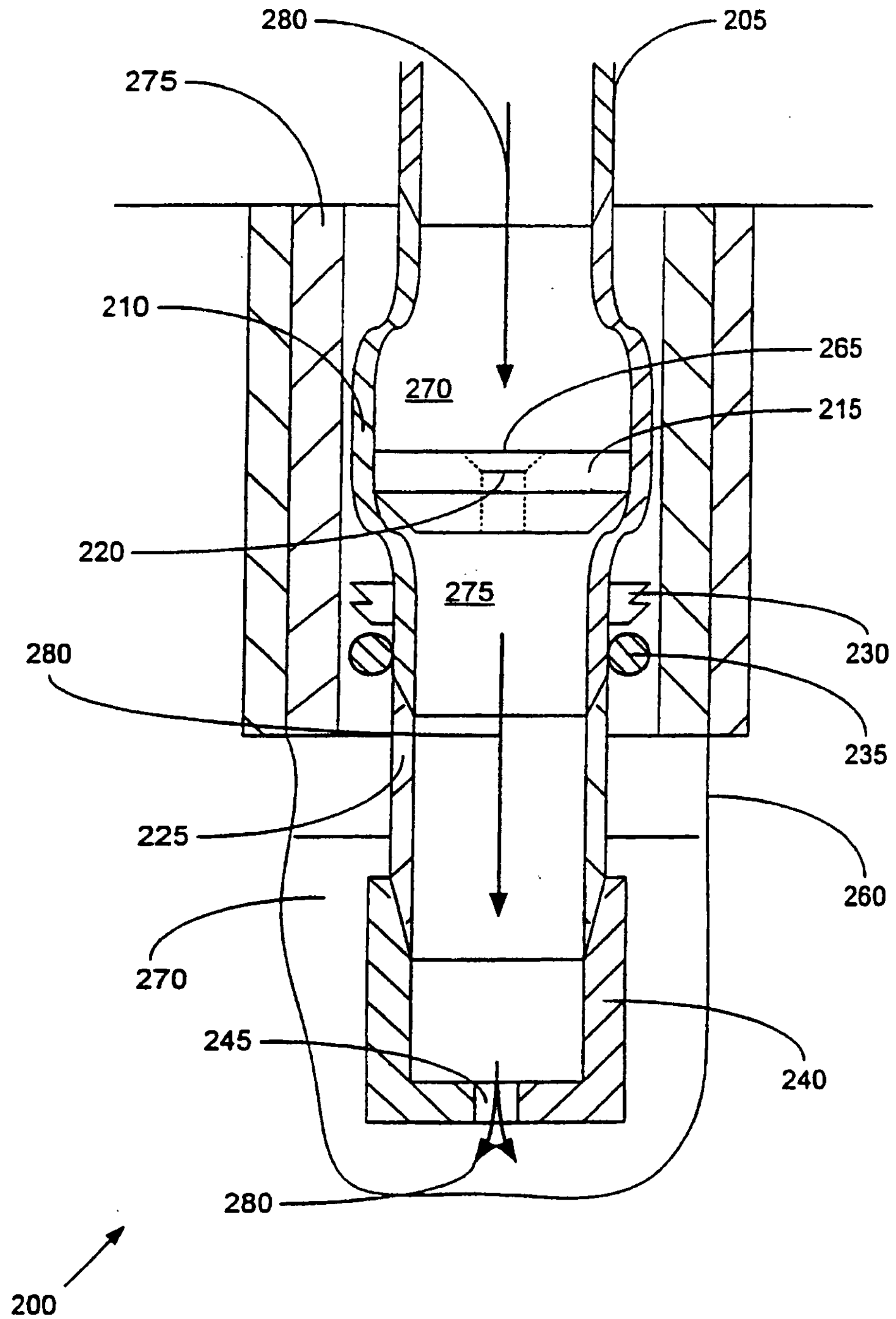
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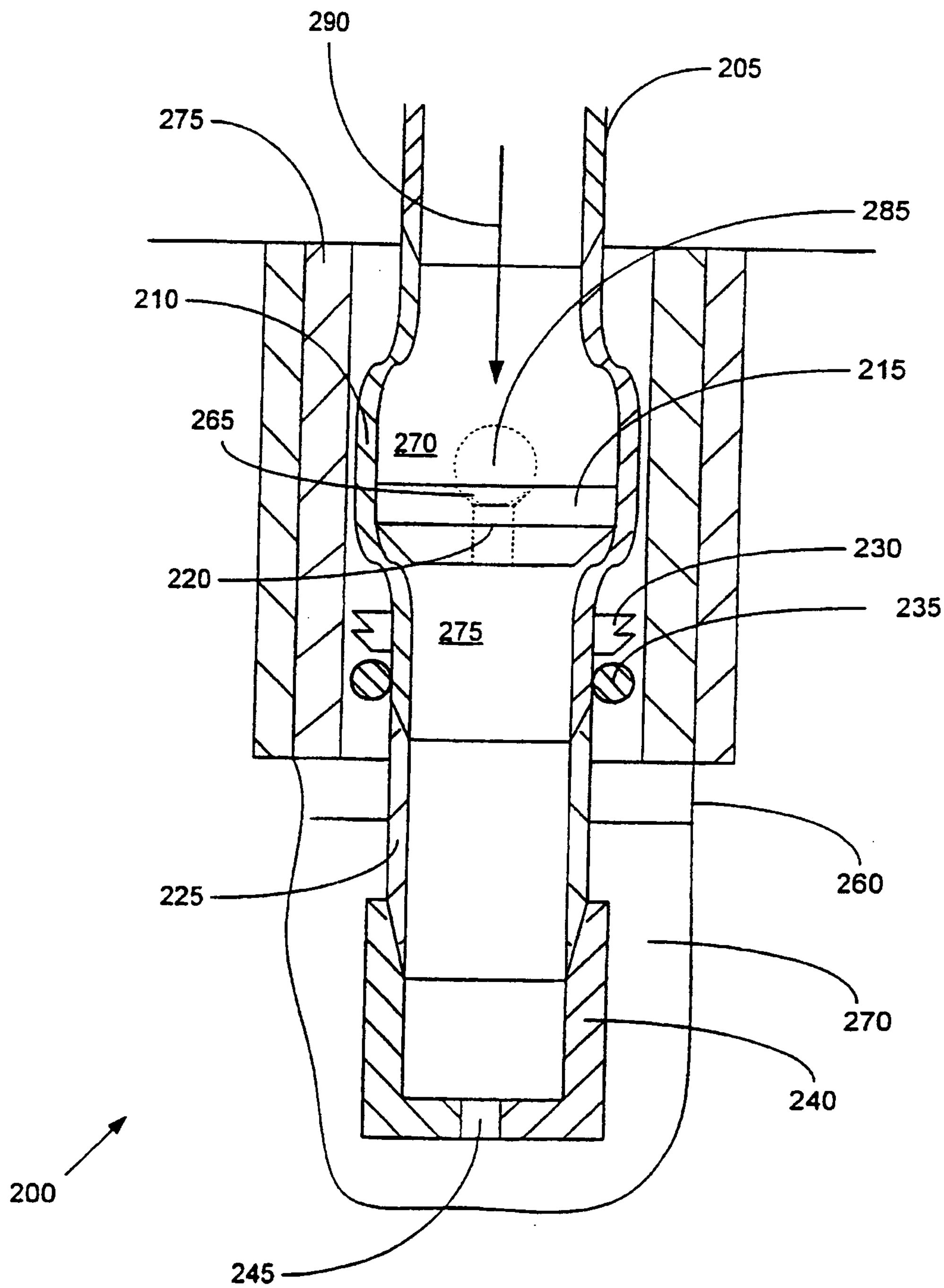
FIG. 2b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245

FIG. 2c

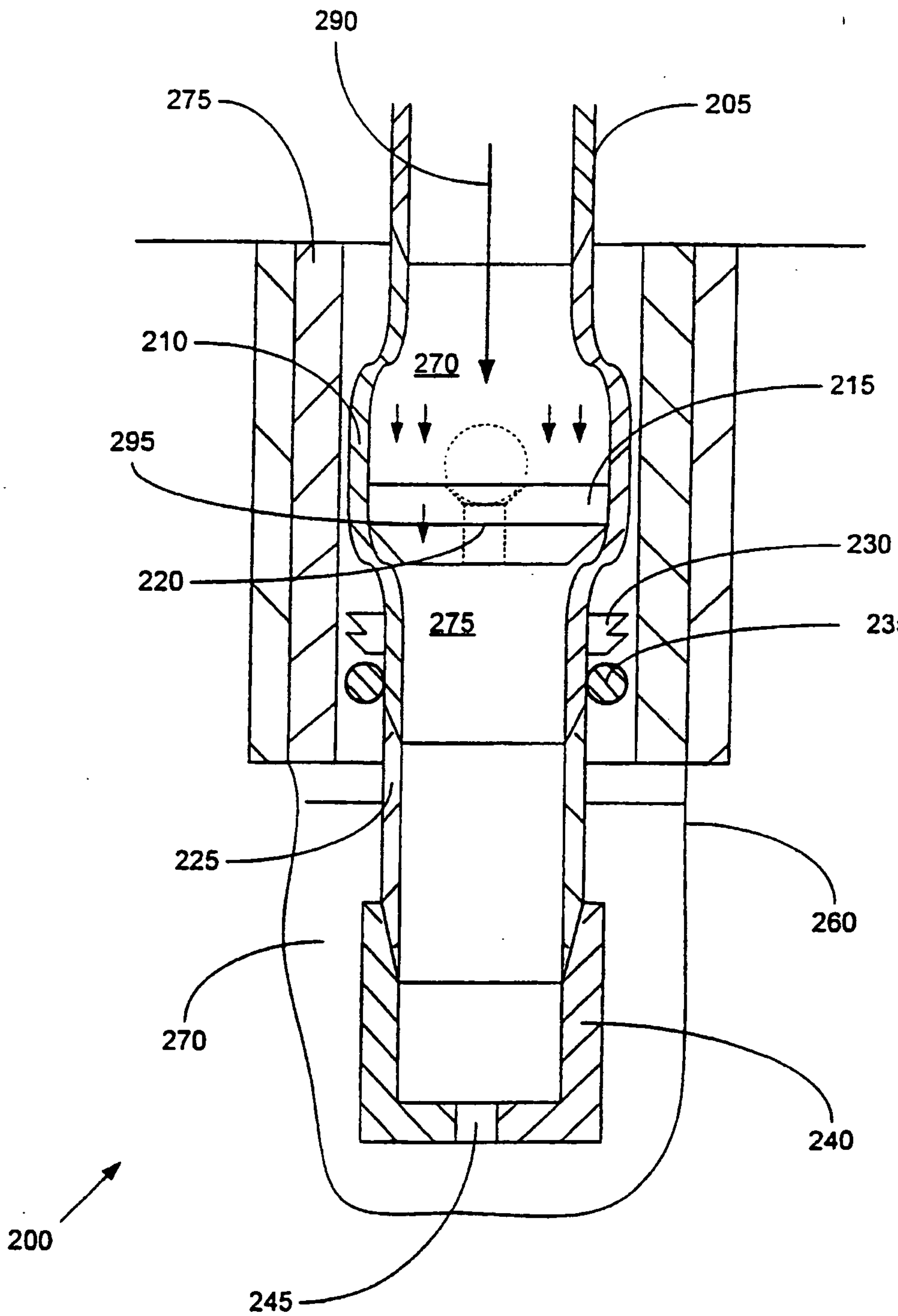
290
275
205
210
270
215
295
230
220
275
235
225
260
270
240
200
245

FIG. 2d

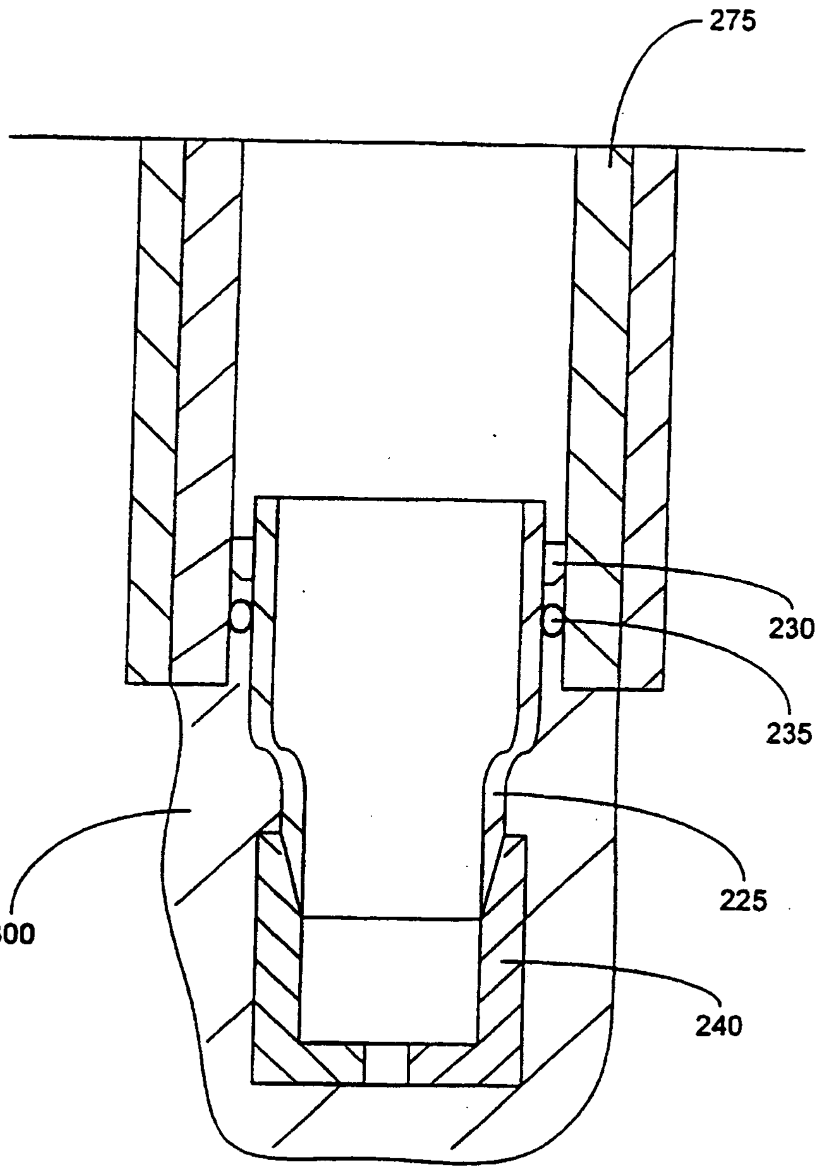

FIG. 2e

EXPANDING A TUBULAR MEMBER

Cross Reference To Related Applications

The present application claims the benefit of the filing date of U.S. provisional patent application serial no. 60/183,546, attorney docket no. 25791.10, filed on 2/18/2000, the disclosure of which is incorporated herein by reference.

This application is a continuation-in-part of U.S. Serial No. 09/559,122, attorney docket number 25791.23.02, filed on 4/26/2000, which issued as United States Patent Number 6,604,763, which claimed the benefit of the filing date of U.S. provisional patent application serial number 60/131,106, filed on 4/26/1999, which was a continuation-in-part of U.S. patent application serial number 09/523,468, attorney docket number 25791.11.02, filed on 3/10/2000, which claimed the benefit of the filing date of U.S. provisional patent application serial no. 60/124,042, filed on 3/11/1999, which was a continuation-in-part of U.S. patent application serial number 09/510,913, attorney docket number 25791.7.02, which claimed the benefit of the filing date of U.S. provisional patent application serial number 60/121,702, filed on 2/25/1999, which was a continuation-in-part of U.S. patent application serial number 09/502,350, attorney docket number 25791.8.02, filed on 2/10/2000, which claimed the benefit of the filing date of U.S. provisional patent application serial number 60/119,611, attorney docket number 25791.8, filed on 2/11/1999, which was a continuation-in-part of U.S. patent number 6,497,289, attorney docket number 25791.3.02, filed on 12/3/1999, which claimed the benefit of the filing date of U.S. provisional patent application serial number 60/111,293, filed on 12/7/1998.

The present application is related to the following U.S. patents and applications: (1) utility patent number 6,328,113, attorney docket number 25791.9.02, filed on 11-15-1999, which claimed the benefit of the filing date of provisional patent application number 60/108,558, attorney docket number 25791.9, filed on 11-16-1998; (2) utility patent number 6,497,289, attorney docket number 25791.3.02, filed on 12-3-1999, which claimed the benefit of the filing date of provisional patent application number 60/111,293, attorney docket number 25791.3, filed on 12-7-1998; (3) utility patent application number 09/502,350, attorney docket number 25791.8.02, filed on 2-10-2000, which claimed the benefit of the filing date of provisional patent application number 60/119,611, attorney docket number 25791.8, filed on 2-11-1999; (4) provisional patent application number 60/121,702, attorney docket number 25791.7,

filed on 2-25-1999; (5) provisional patent application number 60/121,841, attorney docket number 25791.12, filed on 2-26-1999; (6) provisional patent application number 60/121,907, attorney docket number 25791.16, filed on 2-26-1999; (7) provisional patent application number 60/124,042, attorney docket number 25791.11, filed on 3-11-1999; (8) provisional patent application number 60/131,106, attorney docket number 25791.23, filed on 4-26-1999; (9) provisional patent application number 60/137,998, attorney docket number 25791.17, filed on 6-7-1999; (10) provisional patent application number 60/143,039, attorney docket number 25791.26, filed on 7-9-1999; (11) provisional patent application number 60/146,203, attorney docket number 25791.25, filed on 7-29-1999; (12) provisional patent application number 60/154,047, attorney docket number 25791.29, filed on 9-16-1999; (13) provisional patent application number 60/159,082, attorney docket number 25791.34, filed on 10-12-1999; (14) provisional patent application number 60/159,039, attorney docket number 25791.36, filed on 10-12-1999; (15) provisional patent application number 60/159,033, attorney docket number 25791.37, filed on 10-12-1999; (16) provisional patent application number 60/162,671, attorney docket number 25791.27, filed on 11-01-1999.

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping,

cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that typically includes a surface casing, a number of production and/or drilling spools, valving, and a Christmas tree. Typically the wellhead further includes a concentric arrangement of casings including a production casing and one or more intermediate casings. The casings are typically supported using load bearing slips positioned above the ground. The conventional design and construction of wellheads is expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed in the newly drilled section of the wellbore. This delays the completion of a well.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary

According to the present invention there is provided an apparatus for radially expanding a tubular member, comprising:

a first tubular member;

a second tubular member coupled to the first tubular member;

a third tubular member coupled to the second tubular member;

one or more slips coupled to the exterior surface of the third tubular member; and

a mandrel having a conical outer surface including an angle of attack between 1 to 30 degrees and a surface hardness ranging from 58 to 62 Rockwell C positioned within the second tubular member and coupled to an end portion of the third tubular member;

wherein the inside diameter of the second tubular member is greater than the inside diameters of the first and third tubular members;

wherein the mandrel includes a fluid passage having an inlet adapted to receive a fluid stop member.

Preferably, the first tubular member includes one or more sealing members coupled to the exterior surface of the first tubular member.

Preferably, the second tubular member includes one or more sealing members coupled to the exterior surface of the second tubular member.

Preferably, the third tubular member includes one or more sealing members coupled to the exterior surface of the third tubular member.

Preferably, the apparatus further comprises a means for displacing the mandrel with respect to the third tubular member.

Preferably, the apparatus further comprises a means for displacing the mandrel with respect to the second tubular member.

Preferably, the mandrel is heat treated.

Preferably, the mandrel is expandable.

Preferably, the mandrel comprises one or more materials selected from the group consisting of machine tool steel, ceramics, tungsten carbide, and titanium.

Brief Description of the Drawings

FIG. 1a is a fragmentary cross-section illustration of an apparatus and method for expanding tubular members.

FIG. 1b is another fragmentary cross-sectional illustration of the apparatus of FIG. 1a.

FIG. 1c is another fragmentary cross-sectional illustration of the apparatus of FIG. 1a.

FIG. 2a is a fragmentary cross-section illustration of an apparatus and method for expanding tubular members.

FIG. 2b is another fragmentary cross-sectional illustration of the apparatus of FIG. 2a.

FIG. 2c is another fragmentary cross-sectional illustration of the apparatus of FIG. 2a.

FIG. 2d is another fragmentary cross-sectional illustration of the apparatus of FIG. 2a.

FIG. 2e is another fragmentary cross-sectional illustration of the apparatus of FIG. 2a.

Detailed Description

Referring now to FIGS. 1a, 1b and 1c, an apparatus 100 for expanding a tubular member will be described. The apparatus 100 includes a support member 105, a packer 110, a first fluid conduit 115, an annular fluid passage 120, fluid inlets 125, an

annular seal 130, a second fluid conduit 135, a fluid passage 140, a mandrel 145, a mandrel launcher 150, a tubular member 155, slips 160, and seals 165. The apparatus 100 is used to radially expand the tubular member 155. In this manner, the apparatus 100 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. The apparatus 100 is used to clad at least a portion of the tubular member 155 onto a preexisting tubular member.

The support member 105 is preferably coupled to the packer 110 and the mandrel launcher 150. The support member 105 preferably is a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 105 is preferably selected to fit through a preexisting section of wellbore casing 170. In this manner, the apparatus 100 may be positioned within the wellbore casing 170. The support member 105 is releasably coupled to the mandrel launcher 150. In this manner, the support member 105 may be decoupled from the mandrel launcher 150 upon the completion of an extrusion operation.

The packer 110 is coupled to the support member 105 and the first fluid conduit 115. The packer 110 preferably provides a fluid seal between the outside surface of the first fluid conduit 115 and the inside surface of the support member 105. In this manner, the packer 110 preferably seals off and, in combination with the support member 105, first fluid conduit 115, second fluid conduit 135, and mandrel 145, defines an annular chamber 175. The packer 110 may be any number of conventional commercially available packers modified in accordance with the teachings of the present disclosure. The packer 110 is an RTTS packer available from Halliburton Energy Services in order to optimally provide high load and pressure containment capacity while also allowing the packer to be set and unset multiple times without having to pull the packer out of the wellbore.

The first fluid conduit 115 is coupled to the packer 110 and the annular seal 130. The first fluid conduit 115 preferably is an annular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The first fluid conduit 115 includes one or more fluid inlets 125 for conveying fluidic materials from the annular fluid passage 120 into the chamber 175.

The annular fluid passage 120 is defined by and positioned between the interior surface of the first fluid conduit 115 and the interior surface of the second fluid conduit 135. The annular fluid passage 120 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) and 0 to 620.528 bar (0 to 9,000 psi) in order to optimally provide flow rates and operational pressures for the radial expansion process.

The fluid inlets 125 are positioned in an end portion of the first fluid conduit 115. The fluid inlets 125 preferably are adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to optimally provide flow rates and operational pressures for the radial expansion process.

The annular seal 130 is coupled to the first fluid conduit 115 and the second fluid conduit 135. The annular seal 130 preferably provides a fluid seal between the interior surface of the first fluid conduit 115 and the exterior surface of the second fluid conduit 135. The annular seal 130 preferably provides a fluid seal between the interior surface of the first fluid conduit 115 and the exterior surface of the second fluid conduit 135 during relative axial motion of the first fluid conduit 115 and the second fluid conduit 135. The annular seal 130 may be any number of conventional commercially available seals such as, for example, O-rings, Polypak (RTM) seals, or metal spring energized seals. The annular seal 130 is a Polypak(RTM) seal available from Parker Seals.

The second fluid conduit 135 is coupled to the annular seal 130 and the mandrel 145. The second fluid conduit preferably is a tubular member fabricated from any number of conventional commercially available materials such as, for example, coiled tubing, oilfield country tubular goods, low alloy steel, stainless steel, or low carbon steel. The second fluid conduit 135 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to optimally provide flow rates and operational pressures for the radial expansion process.

The fluid passage 140 is coupled to the second fluid conduit 135 and the mandrel 145. The fluid passage 140 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to optimally provide flow rates and operational pressures for the radial expansion process.

The mandrel 145 is coupled to the second fluid conduit 135 and the mandrel launcher 150. The mandrel 145 preferably is an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other high strength alloys. The angle of the conic section of the mandrel 145 ranges from about 1 to 30 degrees in order to optimally expand the mandrel launcher 150 and tubular member 155 in the radial direction. The surface of the conic section ranges from about 58 to 62 Rockwell C in order to optimally provide high yield strength. The expansion cone 145 is heat treated in order to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness. Alternatively, the mandrel 145 is expandible in order to further optimally augment the radial expansion process.

The mandrel launcher 150 is coupled to the support member 105, the mandrel 145, and the tubular member 155. The mandrel launcher 150 preferably is a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 150 at one end is adapted to mate with the mandrel 145, and at the other end, the cross-sectional area of the mandrel launcher 150 is adapted to match the cross-sectional area of the tubular member 155. The wall thickness of the mandrel launcher 150 ranges from about 50 to 100 % of the wall thickness of the tubular member 155 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 150 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher 150 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 155 in order to optimally match the burst strength of the tubular member 155. The mandrel launcher 150 is removably coupled to the tubular member

155. In this manner, the mandrel launcher 150 may be removed from the wellbore 180 upon the completion of an extrusion operation.

Alternatively, the support member 105 and the mandrel launcher 150 are integrally formed. The support member 105 preferably terminates above the top of the packer 110. The fluid conduits 115 and/or 135 provide structural support for the apparatus 100, using the packer 110 to couple together the elements of the apparatus 100. During the radial expansion process, the packer 110 may be unset and reset, after the slips 160 have anchored the tubular member 155 to the previous casing 170, within the tubular member 155, between radial expansion operations. In this manner, the packer 110 is moved downhole and the apparatus 100 is re-stroked.

The tubular member 155 is coupled to the mandrel launcher, the slips 160 and the seals 165. The tubular member 155 preferably is a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 155 is fabricated from oilfield country tubular goods.

The slips 160 are coupled to the outside surface of the tubular member 155. The slips 160 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 155. In this manner, the slips 160 provide structural support for the expanded tubular member 155. The slips 160 may be any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide slips, RTTS packer wicker type mechanical slips or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. The slips 160 are RTTS packer tungsten carbide mechanical slips available from Halliburton Energy Services. The slips 160 are adapted to support axial forces ranging from about 0 to 3336.2 kN (0 to 750,000 lbf).

The seals 165 are coupled to the outside surface of the tubular member 155. The seals 165 preferably provide a fluidic seal between the outside surface of the expanded tubular member 155 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 155. In this manner, the seals 165 provide a fluidic seal for the expanded tubular member 155. The seals 165 may be any number of conventional commercially available seals such as, for example, nitrile rubber, lead, Aflas(RTM) rubber, Teflon(RTM) , epoxy, or other elastomers. The

seals 165 are rubber seals available from numerous commercial vendors in order to optimally provide pressure sealing and load bearing capacity.

During operation of the apparatus 100, the apparatus 100 is preferably lowered into a wellbore 180 having a preexisting section of wellbore casing 170. The apparatus 100 is positioned with at least a portion of the tubular member 155 overlapping with a portion of the wellbore casing 170. In this manner, the radial expansion of the tubular member 155 will preferably cause the outside surface of the expanded tubular member 155 to couple with the inside surface of the wellbore casing 170. The radial expansion of the tubular member 155 will also cause the slips 160 and seals 165 to engage with the interior surface of the wellbore casing 170. In this manner, the expanded tubular member 155 is provided with enhanced structural support by the slips 160 and an enhanced fluid seal by the seals 165.

As illustrated in FIG. 1b, after placement of the apparatus 100 in an overlapping relationship with the wellbore casing 170, a fluidic material 185 is preferably pumped into the chamber 175 using the fluid passage 120 and the inlet passages 125. The fluidic material is pumped into the chamber 175 at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to optimally provide flow rates and operational pressures for the radial expansion process. The pumped fluidic material 185 increase the operating pressure within the chamber 175. The increased operating pressure in the chamber 175 then causes the mandrel 145 to extrude the mandrel launcher 150 and tubular member 155 off of the face of the mandrel 145. The extrusion of the mandrel launcher 150 and tubular member 155 off of the face of the mandrel 145 causes the mandrel launcher 150 and tubular member 155 to expand in the radial direction. Continued pumping of the fluidic material 185 preferably causes the entire length of the tubular member 155 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 185 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 100. The apparatus 100 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process.

The extrusion process causes the mandrel 145 to move in an axial direction 185. During the axial movement of the mandrel, the fluid passage 140 conveys fluidic

material 190 displaced by the moving mandrel 145 out of the wellbore 180. In this manner, the operational efficiency and speed of the extrusion process is enhanced.

The extrusion process includes the injection of a hardenable fluidic material into the annular region between the tubular member 155 and the bore hole 180. In this manner, a hardened sealing layer is provided between the expanded tubular member 155 and the interior walls of the wellbore 180.

As illustrated in FIG. 1c, upon the completion of the extrusion process, the support member 105, packer 110, first fluid conduit 115, annular seal 130, second fluid conduit 135, mandrel 145, and mandrel launcher 150 are moved from the wellbore 180.

Alternatively, the apparatus 100 is used to repair a preexisting wellbore casing 170 or pipeline. Both ends of the tubular member 155 preferably include slips 160 and seals 165.

Alternatively, the apparatus 100 is used to form a tubular structural support for a building or offshore structure.

Referring now to FIGS. 2a, 2b, 2c, 2d, and 2e, an apparatus 200 for expanding a tubular member will be described. The apparatus 200 includes a support member 205, a mandrel launcher 210, a mandrel 215, a first fluid passage 220, a tubular member 225, slips 230, seals 235, a shoe 240, and a second fluid passage 245. The apparatus 200 is used to radially expand the mandrel launcher 210 and tubular member 225. In this manner, the apparatus 200 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. The apparatus 200 is used to clad at least a portion of the tubular member 225 onto a preexisting structural member.

The support member 205 is preferably coupled to the mandrel launcher 210. The support member 205 preferably is a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 205, the mandrel launcher 210, the tubular member 225, and the shoe 240 are preferably selected to fit through a preexisting section of wellbore casing 270. In this manner, the apparatus 200 may be positioned within the wellbore casing 270. The support member 205 is releasably coupled to the mandrel launcher 210. In this

manner, the support member 205 may be decoupled from the mandrel launcher 210 upon the completion of an extrusion operation.

The mandrel launcher 210 is coupled to the support member 205 and the tubular member 225. The mandrel launcher 210 preferably is a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 210 at one end is adapted to mate with the mandrel 215, and at the other end, the cross-sectional area of the mandrel launcher 210 is adapted to match the cross-sectional area of the tubular member 225. The wall thickness of the mandrel launcher 210 ranges from about 50 to 100 % of the wall thickness of the tubular member 225 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 210 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher 210 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 225 in order to optimally match the burst strength of the tubular member 225. The mandrel launcher 210 is removably coupled to the tubular member 225. In this manner, the mandrel launcher 210 may be removed from the wellbore 260 upon the completion of an extrusion operation.

The mandrel 215 is coupled to the mandrel launcher 210. The mandrel 215 preferably is an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, ceramics, tungsten carbide, titanium or other high strength alloys. The angle of the conic section of the mandrel 215 ranges from about 0 to 30 degrees in order to optimally expand the mandrel launcher 210 and the tubular member 225 in the radial direction. The surface of the conic section ranges from about 58 to 62 Rockwell C in order to optimally provide high yield strength. The expansion cone 215 is heat treated in order to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness. Alternatively, the mandrel 215 is expandible in order to further optimally augment the radial expansion process.

The fluid passage 220 is positioned within the mandrel 215. The fluid passage 220 is preferably adapted to convey fluidic materials such as cement, water, epoxy,

lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000) gallons/minute in order to optimally provide flow rates and operational pressures for the radial expansion process. The fluid passage 220 preferably includes an inlet 265 adapted to receive a plug, or other similar device. In this manner, the interior chamber 270 above the mandrel 215 may be fluidicly isolated from the interior chamber 275 below the mandrel 215.

The tubular member 225 is coupled to the mandrel launcher 210, the slips 230 and the seals 235. The tubular member 225 preferably is a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 225 is fabricated from oilfield country tubular goods.

The slips 230 are coupled to the outside surface of the tubular member 225. The slips 230 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 225. In this manner, the slips 230 provide structural support for the expanded tubular member 225. The slips 230 may be any number of conventional commercially available slips such as, for example, RTTS packer tungsten carbide mechanical slips, RTTS packer wicker type mechanical slips, or Model 3L retrievable bridge plug tungsten carbide upper mechanical slips. The slips 230 are adapted to support axial forces ranging from about 0 to 3336.2 kN (0 to 750,000 lbf).

The seals 235 are coupled to the outside surface of the tubular member 225. The seals 235 preferably provide a fluidic seal between the outside surface of the expanded tubular member 225 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 225. In this manner, the seals 235 provide a fluidic seal for the expanded tubular member 225. The seals 235 may be any number of conventional commercially available seals such as, for example, nitrile rubber, lead, Aflas(RTM) rubber, Teflon(RTM), epoxy or other elastomers. The seals 235 are conventional rubber seals available from various commercial vendors in order to optimally provide pressure sealing and load bearing capacity.

The shoe 240 is coupled to the tubular member 225. The shoe 240 preferably is a substantially tubular member having a fluid passage 245 for conveying fluidic materials from the chamber 275 to the annular region 270 outside of the apparatus

200. The shoe 240 may be any number of conventional commercially available shoes such as, for example, a Super Seal(RTM) II float shoe, a Super Seal(RTM) II Down-Jet float shoe, or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. The shoe 240 is an aluminum down-jet guide shoe with a sealing sleeve for a latch down plug, available from Halliburton Energy Services, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 225 in the wellbore, optimally provide a fluidic seal between the interior and exterior diameters of the overlapping joint between the tubular members, and optimally facilitate the complete drilling out of the shoe and plug upon the completion of the cementing and radial expansion operations.

During operation of the apparatus 200, the apparatus 200 is preferably lowered into a wellbore 260 having a preexisting section of wellbore casing 275. The apparatus 200 is positioned with at least a portion of the tubular member 225 overlapping with a portion of the wellbore casing 275. In this manner, the radial expansion of the tubular member 225 will preferably cause the outside surface of the expanded tubular member 225 to couple with the inside surface of the wellbore casing 275. The radial expansion of the tubular member 225 will also cause the slips 230 and seals 235 to engage with the interior surface of the wellbore casing 275. In this manner, the expanded tubular member 225 is provided with enhanced structural support by the slips 230 and an enhanced fluid seal by the seals 235.

As illustrated in FIG. 2b, after placement of the apparatus 200 in an overlapping relationship with the wellbore casing 275, a fluidic material 280 is preferably pumped into the chamber 270. The fluidic material 280 then passes through the fluid passage 220 into the chamber 275. The fluidic material 280 then passes out of the chamber 275, through the fluid passage 245, and into the annular region 270. The fluidic material 280 is pumped into the chamber 270 at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to optimally provide flow rates and operational pressures for the radial expansion process. The fluidic material 280 is a hardenable fluidic sealing material in order to form a hardened outer annular member around the expanded tubular member 225.

As illustrated in FIG. 2c, at some later point in the process, a ball 285, plug or other similar device, is introduced into the pumped fluidic material 280. The ball 285 mates with and seals off the inlet 265 of the fluid passage 220. In this manner, the chamber 270 is fluidicly isolated from the chamber 275.

As illustrated in FIG. 2d, after placement of the ball 285 in the inlet 265 of the fluid passage 220, a fluidic material 290 is pumped into the chamber 270. The fluidic material is preferably pumped into the chamber 270 at operating pressures and flow rates ranging from about 0 to 620.528 bar (0 to 9,000 psi) and 0 to 11356.24 litres/minute (0 to 3,000 gallons/minute) in order to provide optimal operating efficiency. The fluidic material 290 may be any number of conventional commercially available materials such as, for example, water, drilling mud, cement, epoxy, or slag mix. The fluidic material 290 is a non-hardenable fluidic material in order to maximize operational efficiency.

Continued pumping of the fluidic material 290 increases fluidic material 280 increases the operating pressure within the chamber 270. The increased operating pressure in the chamber 270 then causes the mandrel 215 to extrude the mandrel launcher 210 and tubular member 225 off of the conical face of the mandrel 215. The extrusion of the mandrel launcher 210 and tubular member 225 off of the conical face of the mandrel 215 causes the mandrel launcher 210 and tubular member 225 to expand in the radial direction. Continued pumping of the fluidic material 290 preferably causes the entire length of the tubular member 225 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 290 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 200. The apparatus 200 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process. The extrusion process causes the mandrel 215 to move in an axial direction 290.

As illustrated in FIG. 2e, upon the completion of the extrusion process, the support member 205, packer 210, first fluid conduit 215, annular seal 230, second fluid conduit 235, mandrel 245, and mandrel launcher 250 are removed from the wellbore 280. The resulting new section of wellbore casing includes the preexisting wellbore casing 275, the expanded tubular member 225, the slips 230, the seals 235, the shoe 240, and an outer annular layer 300 of hardened fluidic material.

Alternatively, the apparatus 200 is used to repair a preexisting wellbore casing or pipeline. Both ends of the tubular member 255 preferably include slips 260 and seals 265.

Alternatively, the apparatus 200 is used to form a tubular structural support for a building or offshore structure.

The tubular members 105 and 225; shoes 240; expansion cone launchers 150 and 210; and expansion cones 145 and 215 are provided substantially as described in one or more of the following U.S. patents and applications: (1) utility patent number 6,328,113, attorney docket number 25791.9.02, filed on 11-15-1999, which claimed the benefit of the filing date of provisional patent application number 60/108,558, attorney docket number 25791.9, filed on 11-16-1998; (2) utility patent number 6,497,289, attorney docket number 25791.3.02, filed on 12-3-1999, which claimed the benefit of the filing date of provisional patent application number 60/111,293, attorney docket number 25791.3, filed on 12-7-1998; (3) utility patent application number 09/502,350, attorney docket number 25791.8.02, filed on 2-10-2000, which claimed the benefit of the filing date of provisional patent application number 60/119,611, attorney docket number 25791.8, filed on 2-11-1999; (4) provisional patent application number 60/121,702, attorney docket number 25791.7, filed on 2-25-1999; (5) provisional patent application number 60/121,841, attorney docket number 25791.12, filed on 2-26-1999; (6) provisional patent application number 60/121,907, attorney docket number 25791.16, filed on 2-26-1999; (7) provisional patent application number 60/124,042, attorney docket number 25791.11, filed on 3-11-1999; (8) provisional patent application number 60/131,106, attorney docket number 25791.23, filed on 4-26-1999; (9) provisional patent application number 60/137,998, attorney docket number 25791.17, filed on 6-7-1999; (10) provisional patent application number 60/143,039, attorney docket number 25791.26, filed on 7-9-1999; (11) provisional patent application number 60/146,203, attorney docket number 25791.25, filed on 7-29-1999; (12) provisional patent application number 60/154,047, attorney docket number 25791.29, filed on 9-16-1999; (13) provisional patent application number 60/159,082, attorney docket number 25791.34, filed on 10-12-1999; (14) provisional patent application number 60/159,039, attorney docket number 25791.36, filed on 10-12-1999; (15) provisional patent application number 60/159,033, attorney docket number 25791.37, filed on 10-

12-1999; (16) provisional patent application number 60/162,671, attorney docket number 25791.27, filed on 11-01-1999.

Although illustrative aspects of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

CLAIMS

1. An apparatus for radially expanding a tubular member, comprising:
a first tubular member;
a second tubular member coupled to the first tubular member;
a third tubular member coupled to the second tubular member;
one or more slips coupled to the exterior surface of the third tubular member; and
a mandrel having a conical outer surface including an angle of attack between 1 to 30 degrees and a surface hardness ranging from 58 to 62 Rockwell C positioned within the second tubular member and coupled to an end portion of the third tubular member;
wherein the inside diameter of the second tubular member is greater than the inside diameters of the first and third tubular members;
wherein the mandrel includes a fluid passage having an inlet adapted to receive a fluid stop member.

2. The apparatus of claim 1, wherein the first tubular member includes one or more sealing members coupled to the exterior surface of the first tubular member.

3. The apparatus of claim 1, wherein the second tubular member includes one or more sealing members coupled to the exterior surface of the second tubular member.

4. The apparatus of claim 1, wherein the third tubular member includes one or more sealing members coupled to the exterior surface of the third tubular member.

5. The apparatus of claim 1, further comprising a means for displacing the mandrel with respect to the third tubular member.

6. The apparatus of claim 1, further comprising a means for displacing the mandrel with respect to the second tubular member.

7. The apparatus of claim 1, wherein the mandrel is heat treated.

8. The apparatus of claim 1, wherein the mandrel is expandable.

9. The apparatus of claim 1, wherein the mandrel comprises one or more materials selected from the group consisting of machine tool steel, ceramics, tungsten carbide, and titanium.

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